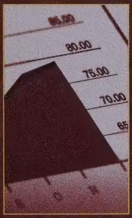
A Powerful Combination.



Solid, long life assets. Proven technical ability. Disciplined financial management.

PENN WEST
PETROLEUM LTD.

2004 Annual Report

CONTENTS

We're an energy company with extensive crude oil and natural gas producing assets across western Canada.

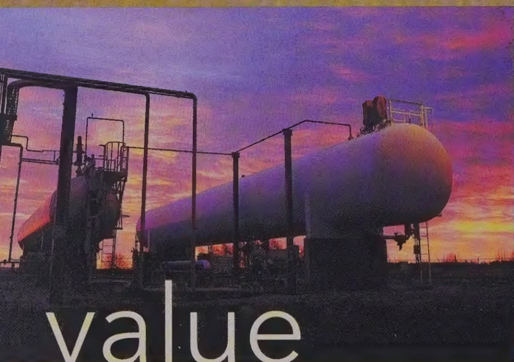
Our proved plus probable reserves of 370 million barrels of oil equivalent (boe) at year end 2004 provide a reserve life index of 9.7 years. Our production averaged almost 106,000 boe per day in 2004. We operate all our major properties with a high working interest, creating value through the dedicated efforts of more than 600 field personnel and head office employees. For more than a decade, we have generated an average annual return on equity of 16 percent.

That's a powerful combination.

A Premier Canadian Energy Producer

- One of the top five Canadian independent crude oil and natural gas producers
- $4.3 billion common share market capitalization* and $5.0 billion enterprise value*
- Record production in 2004
- Five core areas in western Canada with high average working interest
- Growth achieved through internal development and carefully selected acquisitions
- $866 million in capital expenditures in 2004, active capital program in 2005
- 5.8 million net acres undeveloped land at year end 2004

*Based on 2004 year end closing price.



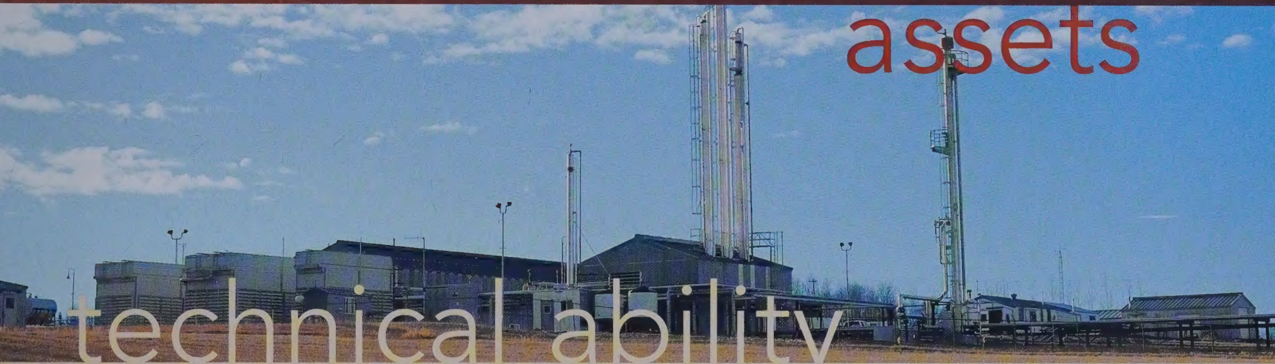
- Record cash flow in 2004
- Strong share price appreciation over 12 years
- Quarterly cash dividends of $0.125 per share in 2004, $0.20 per share for first quarter 2005
- Underlying metrics – growth in production per share and cash flow per share – support ongoing value creation
- Control over cash costs and focus on high netback commodities
- Value preservation through careful financial risk management

Size: a tool to create value

Penn West has assembled a large, diversified asset base, creating an appropriate risk/reward profile. Our size facilitates access to capital, enabling us to make substantial capital investments to capture emerging opportunities. Penn West has consistently created value for its shareholders. This includes growth in production and increasing cash flow, cash flow per share, strong return on equity, share price appreciation and cash dividends.

- Extensive, diversified, Company operated asset base
- Shallow through medium depth prospects
- Long life light crude oil production
- Conventional heavy oil and cold-pumped in situ oil sands reserves and potential
- Control of processing infrastructure
- 105,800 boe per day average production in 2004, with good balance between oil and natural gas
- 370 million boe proved plus probable reserves at year end 2004
- Reserve life index of 9.7 years on proved plus probable reserves at year end 2004

assets



technical ability

- Demonstrated ability to operate and create value out of broad range of assets
- Pursue a wide range of exploitation, optimization, development and exploration opportunities
- Continuous focus on cost control and commodity value, resulting in high average netbacks
- Successful integration of acquisitions
- Long term, consistent management team and board of directors

Assets + technical ability = further opportunity

Penn West's large, diversified asset base has enabled the Company's technical team to create a broad and deep inventory of opportunities: shallow natural gas development wells, deeper natural gas exploration, enhanced recovery of light oil pools, conventional heavy oil, cold-pumped oil sands and new light oil prospects. Penn West focuses on lower risk opportunities for exploitation, optimization and development, plus carefully selected exploration. Control of key processing infrastructure leverages the Company's ability to pursue new opportunities, limiting capital required to bring on new production. Penn West's 5.8 million net acres of undeveloped land support a multi year opportunity base.

2004 in Review

FINANCIAL ($ millions, except per share amounts and % change)

Years ended December 31	2004	2003[1]	% change
Gross revenues	**1,521.3**	1,394.2	9
Cash flow*	**866.7**	812.8	7
Basic per share	**16.10**	15.11	7
Diluted per share	**15.82**	14.90	6
Net income	**271.8**	446.6	(39)
Basic per share	**5.05**	8.30	(39)
Diluted per share	**4.96**	8.19	(39)
Capital expenditures, net	**865.6**	608.1	42
Bank indebtedness	**503.1**	442.4	14
Shareholders' equity	**1,908.9**	1,654.3	15
Total assets	**3,867.4**	3,309.6	17
Common shares outstanding (millions)			
Weighted average			
Basic	**53.8**	53.8	–
Diluted	**54.8**	54.5	1
Year end			
Basic	**53.9**	53.7	–
Basic plus stock options	**57.6**	57.9	(1)

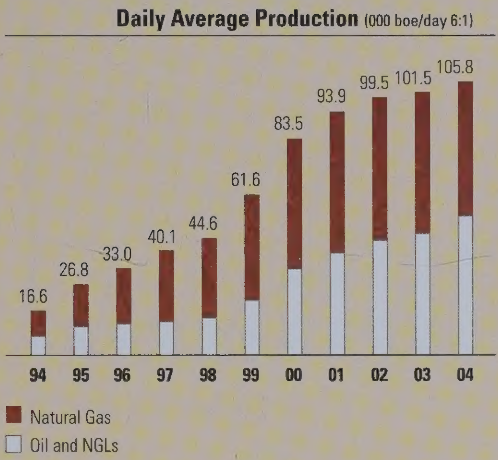
OPERATIONAL

Years ended December 31	2004	2003	% change
Production – annual average			
Light oil and natural gas liquids (bbls/day)	**34,943**	35,479	(2)
Conventional heavy oil (bbls/day)	**18,136**	10,853	67
Total liquids (bbls/day)	**53,079**	46,332	15
Natural gas (mmcf/day)	**316.3**	331.3	(5)
Proved plus probable reserves**			
Oil and liquids (mmbbls)	**240.5**	222.4	8
Natural gas (bcf)	**774**	813	(5)
Wells drilled			
Gross	**439**	750	(41)
Net	**417**	713	(42)
Undeveloped land (000 acres)			
Gross	**6,058**	5,538	9
Net	**5,767**	5,313	9
Average working interest (%)	**95**	96	(1)

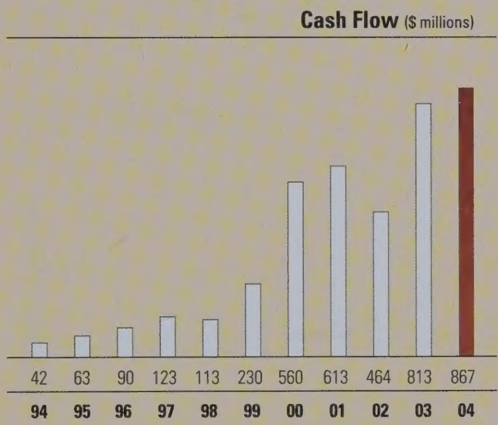
(1) Certain comparative figures have been restated. See note 11 to the Consolidated Financial Statements.

* Cash flow is a non-generally accepted accounting principles term and represents cash flow from operating activities before changes in non-cash working capital, payments for surrendered stock options and expenditures on abandonments.

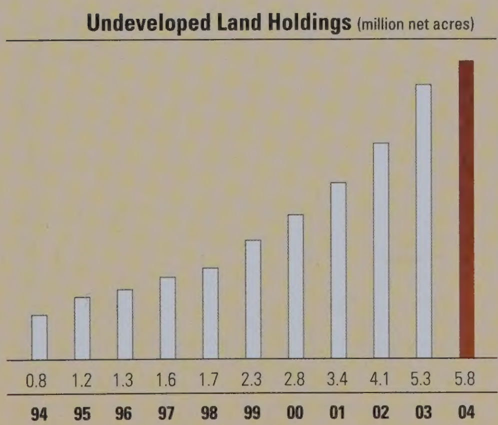
** Company interest.



Penn West has set production records for each of the past 12 years. Penn West operates 86 percent of its production and has an average working interest of 90 percent. The majority of the production is processed through Penn West's own infrastructure.

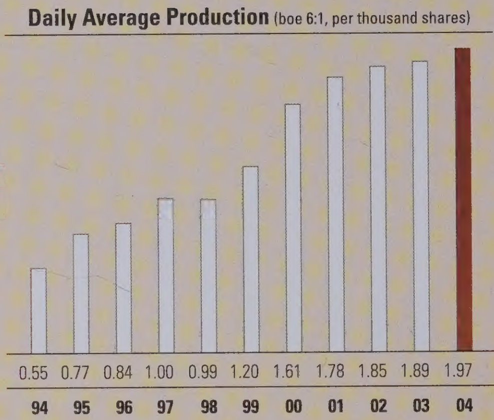


Throughout its history, Penn West has reinvested its cash flow in undeveloped land, exploration and development opportunities and, more recently, cash dividends. As a trust, Penn West will distribute a percentage of its cash flow, reinvesting the remainder in low risk internal development and exploitation opportunities.



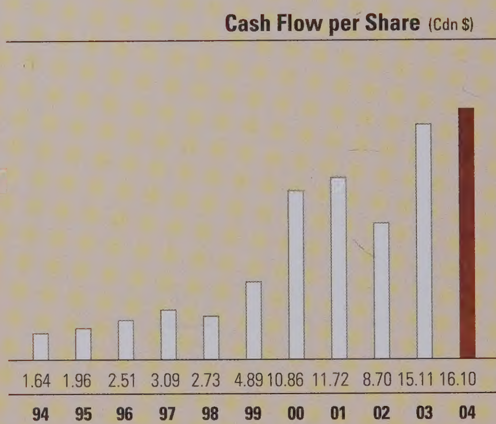
Penn West's large undeveloped land base of 5.8 million net acres at year end 2004 provides a broad base of lower risk development and exploration opportunities. This undeveloped land base is larger than usual for an energy trust, but offers potential for growth through internally generated programs.

The Company's technical ability has delivered success in the field, while disciplined financial management – including limited equity issues and prudent use of debt – has avoided dilutive growth. Penn West's production growth has been accretive on a per share basis.

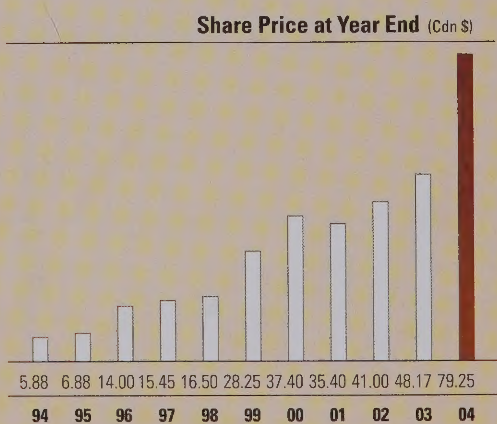


building per share value

Cash flow per share has grown by an average of 39 percent per year for 12 years. The record 2004 cash flow per share indicates our ability to maintain a strong balance sheet, in order to take advantage of opportunities to create shareholder value.



The markets have recognized the positive results generated by Penn West's effective business model. The Company's business successes were complemented by particularly strong crude oil and natural gas prices in 2004.



Letter to Our Shareholders

The most important item on Penn West's agenda in 2004 was the review of strategic alternatives to maximize value for the Company's shareholders, which commenced in March. On August 20, the Company announced that the Board of Directors had recommended Penn West's assets be converted into an income trust. The conversion was contingent on receiving a satisfactory advance income tax ruling from the Canada Revenue Agency. On April 8, 2005 the Company received a satisfactory income tax ruling for its plans to convert the assets and operations of Penn West through a proposed Plan of Arrangement into an energy income trust.

The Company will be issuing an Information Circular for shareholders to be mailed with this Annual Report outlining the Plan of Arrangement ("the Plan") to effect the conversion. This Plan will be subject to approval by a subsequent vote of shareholders. Consequently, this is possibly Penn West's last annual report as an exploration and production company. When the conversion occurs, Penn West will be one of North America's largest energy trusts.

While a potential income trust conversion will change Penn West's corporate structure, it will be in keeping with the ongoing objective of the Company's management team and Board of Directors to maximize long term value for our shareholders.

Many of the operating principles that have helped Penn West succeed over the past 12 years will apply under the trust business model. Penn West has grown through acquisitions combined with exploration and development. Pursuing this approach has created a diverse and balanced portfolio of assets. The Company's assets can be further exploited and optimized through active development.

Penn West's business model as an exploration and production company has delivered steady increases in cash flow per share and daily production per share, as highlighted on the graphs on page 6. Cash flow per share has grown by an average of 39 percent per year for 12 years, while annual cash flow has increased from $9 million in 1993 to $867 million in 2004. Penn West has generated a return on equity averaging 16 percent through this period.

This performance has benefited Penn West's shareholders through steady increases in the Company's share price and, since late 2003, cash dividends. To date, our cash flow has been used to fund further growth. Following our intended trust conversion, Penn West will distribute a percentage of cash flow to unitholders, retaining the balance to reinvest in low risk internal development and exploitation opportunities.

2004 in Review

Penn West's high quality assets, proven technical ability, large asset base and robust commodity prices enabled the Company to achieve strong operational and financial success in 2004. Our combined capital program of $866 million included 417 net wells and was balanced between exploration and development of our existing asset base and $332 million for property acquisitions.

Increasing levels of activity in western Canada resulted in higher costs for oilfield related services, competition for skilled labour and heightened stakeholder awareness. It is clear from planned levels of activity and investment for western Canada in 2005 that these pressures will continue, affecting all energy producers.

In spite of these challenges, Penn West's operations proceeded successfully throughout our five core areas. In February 2004 we acquired 10,000 boe in daily production volumes plus extensive lands and infrastructure in an area complementing existing Penn West operations. With relatively strong commodity prices throughout 2004, Penn West placed more emphasis on early cash flow development projects in the Plains and Central areas. Our programs included horizontal drilling, infill drilling, waterflood optimization, well recompletions and well reactivations. We also prepared to launch a pilot scale carbon dioxide injection scheme for tertiary recovery of light crude oil at our Pembina Cardium play that has potential to add significant reserves over the long term. This pilot scheme is a cooperative effort with both the provincial and federal governments.

Highlights for 2004 included:

- Average production of 105,800 boe per day, an increase of four percent from 2003 and representing daily production of 1.97 boe per thousand common shares outstanding, an increase from 1.89 boe per thousand common shares in 2003;
- Cash flow of $867 million ($16.10 per share), an increase of seven percent from 2003 and a new Company record;
- Capital expenditures of $866 million, approximately equal to 2004 cash flow;
- Year end bank debt of $503 million and a year end bank debt to trailing cash flow ratio of 0.6:1;
- Return on equity of 15.3 percent, in line with our 12 year average performance; and
- Quarterly dividend payments of $0.125 per common share, totalling $27 million for the year.

Corporate Governance

Throughout the strategic review and advance income tax ruling process, Penn West's Board of Directors were actively involved to ensure that long term returns for shareholders were maximized. The alternatives considered, as detailed in previous disclosures, included i) remain an exploration and production company focused on long term capital appreciation, ii) profitably sell or merge the Company, or iii) convert the Company, in whole or in part, to an energy trust.

Formal and informal feedback from shareholders continues to favour trust conversion. The Board's recommendation to take this course was based on careful deliberations that included advice from legal and financial advisors.

Obtaining a favourable income tax ruling was recognized as a necessary precondition to conversion. For a company of Penn West's size and value, the risks of converting without an advance income tax ruling were too great. Particulars of the conversion process are included in the Information Circular, sent to all shareholders with this Annual Report.

Penn West's Asset Base

As a newly formed management team 12 years ago, our business plan was to create a base of longer life assets and reinvest the resulting cash flow into acquiring and developing a mix of longer term growth plays and short term, high return opportunities. Acquisitions have accounted for 40 percent of capital expenditures over this period. These have been successfully integrated with our existing operations. We have focused on exploiting and developing upside opportunities at existing pools and identifying new grassroots growth opportunities.

Today Penn West operates 86 percent of its production and has an average working interest of 90 percent. We control strategic infrastructure at all key properties, providing control of operations and the opportunity to maximize efficiencies and returns. With proved plus probable reserves totalling 370 million boe at year end 2004, 100 percent of which were independently evaluated, Penn West has a reserve life index ("RLI") of 9.7 years.

We have a balanced mix of assets ranging from mature, long life, low risk fields to a significant inventory of raw lands totalling 5.8 million net undeveloped acres at year end 2004. Our portfolio includes opportunities for low risk development and optimization activities such as new or expanded waterfloods, hydrocarbon and carbon dioxide miscible floods, infill drilling, uphole natural gas recompletions and other improved reservoir management techniques. Some properties offer multi zone exploration and development opportunities for both natural gas and oil that can be tied into existing processing infrastructure with relatively low capital outlays.

Trust Strategy Following Conversion

With our diverse asset base and 12 year track record of success, it comes as no surprise that Penn West will be an actively managed trust with a strong focus on field operations and development. The Canadian energy trust group's predominant business model emphasizes sustainability and, therefore, includes a strong component of development and in some cases lower risk exploration. Under this model, Penn West will be well positioned within its peer group of larger Canadian energy trusts.

Following conversion into an energy trust, we intend to retain sufficient cash flow to fund an internal capital program focused on projects including waterfloods and enhanced light oil recovery, conventional heavy oil, emerging light oil plays and numerous shallow to medium depth natural gas opportunities. Project economics will be strengthened by Penn West's control of strategic infrastructure, an important attribute required to control costs and maximize efficiencies.

In addition to our producing asset base, Penn West has two further sources of upside potential. First, Penn West's land base, assembled with a view to supporting a 100,000 boe per day growth company, is larger than usual for an oil and natural gas energy trust. This asset will be actively managed through selective drilling, farmout and joint ventures and will provide excellent opportunity for value creation.

Second, Penn West intends to exploit its experience in making carefully selected, strategic acquisitions that add long term value. We have consolidated many producing areas, timing key acquisitions to periods of lower commodity prices. We examine potential property or corporate acquisitions not merely for their current cash flow, but for their potential for enhancements, efficiency improvements, new production and reserves and other opportunities over a multi year time frame. Following conversion to an energy trust, we intend to continue this focus on acquisition opportunities, which we see as an important factor in enhancing total returns to unitholders.

Access to Capital

Access to competitively priced capital is a significant component of an energy trust's long term success. Penn West's reserve base of 370 million barrels of oil equivalent, and our relatively low debt level, provide the financial capacity to effectively compete for sizeable acquisitions. Timely use of our debt capacity has minimized dilution of shareholders' equity in the past. New equity has financed only 12 percent of our capital expenditures over 12 years. This was, and will remain, an important tool in creating shareholder value.

Following our planned trust conversion, many aspects of our current operating philosophy will help optimize returns to Penn West's unitholders. These policies will ensure the trust has the capability to weather any short term volatility in commodity prices and to stabilize, as much as possible, the level of distributions to unitholders through times of weaker commodity prices.

2005 Economic Environment

Nearing the end of the first quarter of 2005, commodity prices continue to be strong. We are focusing on development activities while emphasizing cost control and operating efficiencies. Penn West's asset base, control of infrastructure and efficient operations provide a foundation to generate good rates of return with low risk.

We take this opportunity to extend our sincere thanks to all of Penn West's employees for their focus and dedication during this period of transition. We also thank the members of Penn West's Board of Directors for their commitment to shareholder value, their sound corporate governance and their wise counsel as we navigate Penn West through these complex issues.

On behalf of the Board of Directors,

N. Murray Edwards
Chairman

William E. Andrew
President

April 8, 2005

Review of Operations

Central

- Backbone of Penn West's light oil production, vast resource of original-oil-in-place
- Light oil, yielding high netbacks
- Secondary recovery plus tertiary recovery (carbon dioxide miscible flood) opportunities

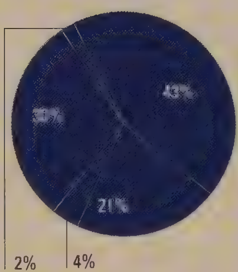
Northern

- Extensive, natural gas prone region
- Low operating costs, high netbacks
- Extensive land base
- Multi zone opportunities for development and grassroots exploration

Peace River Arch

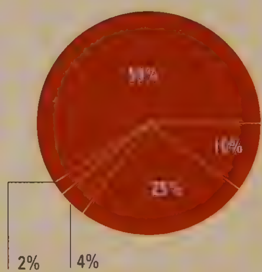
- Productive, multi zone natural gas and light oil pools
- Competitive region
- Opportunities on discrete land areas plus new opportunities on existing properties

Production by Core Area
Average for the Year
(boe 6:1)



%	
43	Central
21	Northern
4	Peace River Arch
30	Plains
2	Southern Saskatchewan

Reserves by Core Area
Average at Year End 2004
(boe 6:1)



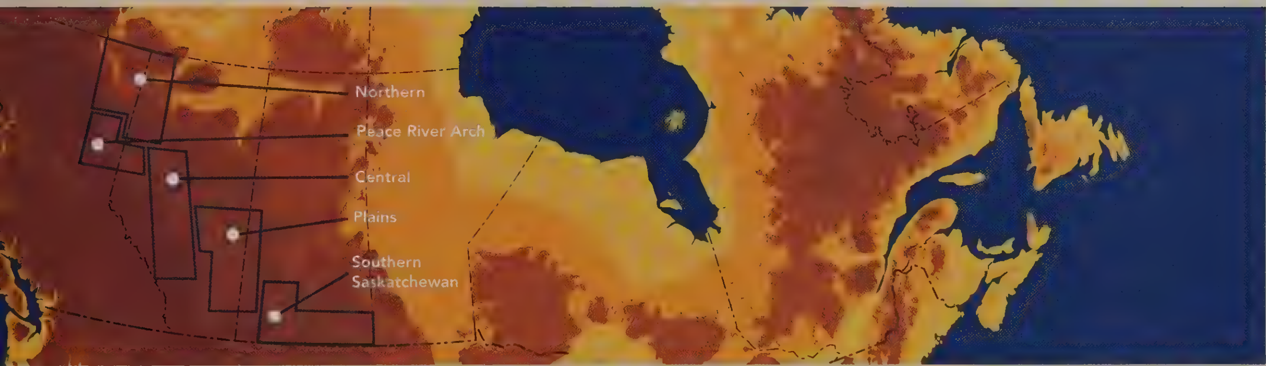
%	
59	Central
10	Northern
25	Plains
4	Peace River Arch
2	Southern Saskatchewan

Plains

- Conventional, long life heavy oil volumes with growth opportunities
- Extensive shallow gas production opportunities, including uphole recompletions
- Ongoing opportunities for area consolidation through acquisitions

Southern Saskatchewan

- Renewed activity through recent acquisitions
- Focus on light to medium gravity crude oil opportunities
- Vertical and horizontal infill drilling, waterfloods, new development



	Central	Northern	Peace River Arch	Plains	Southern Saskatchewan
Undeveloped land					
(000 net acres)	995	2,116	104	1,490	1,062
2004 exit production					
Liquids (bbls/day)*	27,400	200	800	22,700	2,500
Natural gas (mmcf/day)	102	103	21	78	–
Combined (boe/day)	44,400	17,400	4,300	35,700	2,500
Reserves**					
Liquids (mmbbls)*	167.9	0.3	2.5	62.0	7.9
Natural gas (bcf)	308	214	76	175	–
Combined (mmboe)	220	36	15	91	8

* Liquids include light oil, natural gas liquids and conventional heavy oil.

** Company interest, proved plus probable.

Crude Oil

Penn West derived approximately 50 percent of its 2004 production from crude oil and natural gas liquids, of which light to medium gravity crude made up about 65 percent, or 35,000 barrels per day. Penn West is a significant Alberta producer of high quality light oil. Much of our light oil production comes from extensive, low decline pools with a long reserve life index. These reserves that have a 14 year reserve life index are particularly suitable for a royalty trust.

Pembina Cardium

Central Area

With an estimated 7.8 billion barrels of original-oil-in-place ("OOIP"), the Pembina Cardium is the largest conventional light oil pool in Canada. Following a multi year program of consolidation, Penn West operates a significant proportion of this oil pool, which has been producing since the mid 1950s. To date, only a fraction of the OOIP has been recovered. Penn West is fully engaged in tapping the extensive potential to increase the percentage recovery of the pool's OOIP through infill drilling, waterflood enhancement and other optimization.

In 2004, the Company converted 109 older producing wells to water injection while drilling 135 new producing wells as part of a multi year program to finish bringing the pool to 40 acre spacing. This included a new horizontal drilling program at the Lobstick unit.

Penn West is also preparing a program of tertiary or "enhanced" oil recovery using carbon dioxide ("CO_2") as a miscible agent. The Company has gained valuable experience operating a small CO_2 miscible flood at Joffre. By further improving recovery of the OOIP, the Pembina Cardium pool has the potential to yield significant additional reserves over many years.

The pilot scale CO_2 miscible flood program includes a central battery and two injection sites, and is a cooperative effort with both the federal and provincial governments. CO_2 injection commenced in Q1 2005. Success in the pilot scheme could lead to a commercial scale program. Penn West is currently working on detailed project costing, negotiating with potential CO_2 suppliers and working with regulators and governments to advance to a commercial scale project.

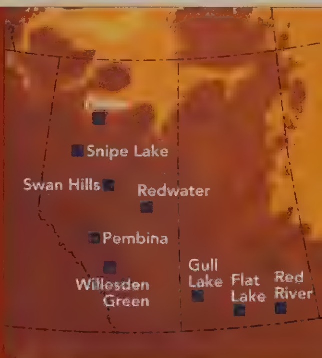
Southern Alberta/Saskatchewan

Plains Area

Promising results at several properties acquired in recent years demonstrate Penn West's ability to exploit acquisitions to create new value. Gull Lake, Shaunavon, Cantuar, Fosterton, Success, Gardenhead and Butte West have all added reserves and production of medium gravity crude oil through reactivation and enhancement of waterfloods plus new development. Some pools are amenable to increased recovery under improved waterflood technology.

In addition, Penn West has assembled a grassroots exploration play in the area, acquiring a new land block totalling 230,000 net acres. Following acquisition of trade seismic plus new Penn West seismic programs, drilling commenced mid year, with 12 wells generating promising results. A follow up program of development and further exploration is now underway.

Penn West's crude oil producing assets are diversified in location, commodity type, maturity and cost/revenue structure. These risk-offsetting characteristics create a stable foundation of long life, low decline production. Extensive opportunities include grassroots light and heavy oil development, secondary and tertiary recovery programs and regional consolidation through ongoing acquisitions.



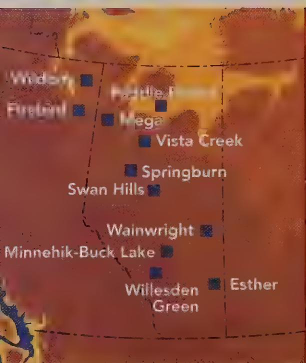
North and South Central Area

Oil Plays

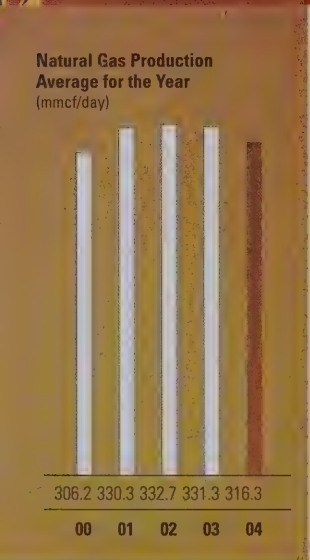
At South Swan Hills, Penn West operates a hydrocarbon miscible flood in the Beaverhill Lake pool. In 2004, the Company initiated a new miscible flood pattern to further enhance the pool's recovery. Other North Central light oil properties, including Shadow, Snipe Lake, Red Earth and Otter, have good future potential for new medium depth exploration and development wells.

Natural Gas

Penn West has natural gas production throughout its core areas of operation. Averaging 316 mmcf per day, natural gas made up approximately 50 percent of Penn West's overall production in 2004. Penn West drilled 195 natural gas wells in 2004. Robust North American prices and the generally lower operating costs incurred by natural gas operations led to strong natural gas netbacks throughout the year. Going forward, Penn West has a large inventory of shallow to medium depth natural gas opportunities.



Penn West's natural gas volumes come mainly from exploration and development of internally generated prospects. Producing pools range from high rate, high cash flow generators to lower rate but stable, long life wells. The Company's multi-million-acre undeveloped land base will support years of further drilling of natural gas targets, including coalbed methane opportunities, to optimize production volumes.



Wildboy

Northern Area

Wildboy is a grassroots Penn West project that has seen production grow to 90 mmcf per day since 1998. Activity has expanded from the medium depth Devonian Jean Marie formation into the shallow Mississippian-era Debolt formation and the deeper Slave Point formation.

Penn West drilled 40 net wells in 2004 at this 100 percent working interest, winter only access property. The 2005 capital program includes 30 wells.

Wildboy is served by a 100 percent Penn West owned and operated natural gas plant and sales pipeline that connects to the Trans Canada system in Alberta.

Firebird

Peace River Arch

Firebird is an established Penn West property with existing Company owned infrastructure that has yielded a new growth opportunity in the emerging regional Notikewin natural gas prospect. Thirteen wells drilled in 2004 added 8 mmcf per day of new natural gas production. These low risk, shallow Notikewin wells flow at stable rates and produce for many years, creating a suitable production and risk profile for a royalty trust. The 2005 capital program includes drilling 17 net wells.

Plains Shallow Gas

Penn West is an active driller for the widespread shallow natural gas pools of the eastern Alberta prairies. These multi zone opportunities include traditional high rate pools from the Mannville Group as well as the lower rate but longer life reserves found in the tighter Viking formation. The Plains Area offers year round access and Penn West has extensive production infrastructure, facilitating timely and economical tie-ins of new wells.

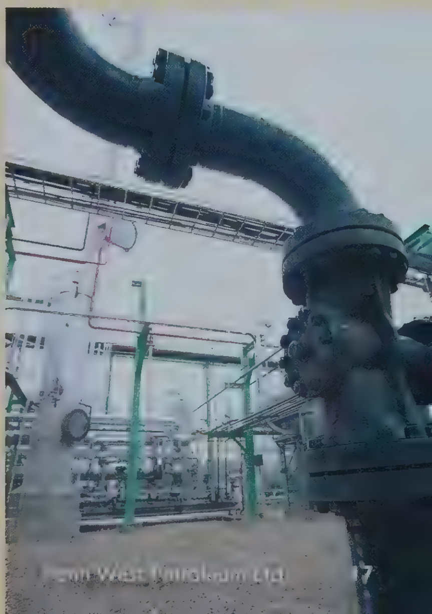
Penn West continued to pursue both Mannville and Viking play types in 2004 as well as a new program of recompleting suspended oil wells for untapped uphole natural gas zones. Penn West drilled 116 natural gas wells in the Plains Area in 2004 and plans to drill 85 wells in 2005.

Central Area Gas

Penn West has, for many years, derived significant production from the multi zone, shallow to medium depth, liquids rich, natural gas pools of west central Alberta. Control of key infrastructure facilitates efficient operations.
Penn West drilled 37 net natural gas wells in the Central area in 2004 and plans to drill up to 60 wells targeting shallow prospects in 2005.

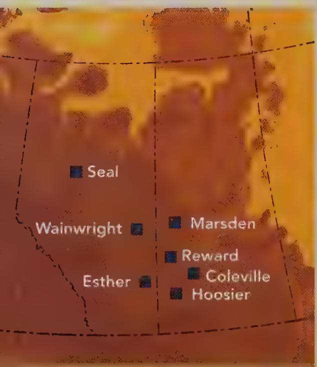
Coalbed Methane (CBM)

Methane gas that is trapped in Alberta's vast coal deposits represents a significant emerging natural gas prospect in western Canada. With a very large known resource-in-place, Penn West believes there is potential for coalbed methane development at Pembina, South Swan Hills and in the Plains Area.



Conventional Heavy Oil

Penn West derived approximately 17 percent of its total volumes, or 18,000 barrels per day, from heavy oil production in 2004. The combination of low geological risk, long reserve life, large volumes of resource in place and potential for secondary and tertiary recovery programs can make heavy oil a suitable play type for a royalty trust. Penn West has the combination of large scale, technical ability and disciplined management required for profitable heavy oil operations. In 2004, Penn West drilled 40 heavy oil wells.



Plains Area

Penn West has large scale, multi zone heavy oil operations at properties in southeast Alberta and southwest Saskatchewan. These have been steadily augmented through a series of acquisitions, the most recent of which was in February 2004, adding production of 10,000 boe per day. Penn West sees numerous opportunities for waterflood expansion, reactivation or optimization on the acquired properties.

In 2004, Penn West drilled 40 heavy oil wells in the Plains Area. Two horizontal wells at Atlee and three multilaterals at Bantry delivered excellent results. More drilling is planned for 2005, including a 30 well Sparky and McLaren program initiated in Q1 2005. With an extensive prospect inventory, Plains Area heavy oil offers multi year development potential.

Seal

North Central Area

The 10° API Bluesky Formation pools at Seal are a form of oil sands, with production attracting the one percent provincial pre payout royalty rate. Seal is tapping one of the few in situ bitumen reservoirs where oil can be brought to surface through cold pumping (without adding steam). This significantly reduces operating and capital costs. Following several new pool discoveries in 2003, Penn West drilled 14 new horizontal wells in 2004 from multi well pads. Going forward, the Company will adjust the timing of development of this long term play to take advantage of opportunities for stronger heavy oil prices.

Operations Statistical Review

1. CAPITAL EXPENDITURES

($ millions)	2004	2003	2002
Net property acquisitions	**$ 332.3**	$ 0.3	$ 230.3
Land acquisition and retention	**18.4**	47.4	42.5
Drilling and completions	**305.7**	349.6	149.3
Facilities and well equipping	**191.8**	191.4	134.2
Geological and geophysical	**16.5**	18.1	15.6
Other	**0.9**	1.3	1.4
Capital expenditures	**$ 865.6**	$ 608.1	$ 573.3

2. UNDEVELOPED LAND BASE

(000 acres at year end)	2004	2003	2002
Gross	**6,058**	5,538	4,402
Net	**5,767**	5,313	4,158
Average working interest (%)	**95**	96	94

3. DRILLING RESULTS

	2004		2003		2002	
	Gross	**Net**	Gross	Net	Gross	Net
Natural gas wells	**209**	**197**	307	299	209	197
Oil wells	**195**	**188**	337	308	112	96
Dry holes	**35**	**32**	106	106	44	42
Total wells	**439**	**417**	750	713	365	335
Average working interest (%)		**95**		95		92
Success rate (%)		**92**		85		87

4. RESERVE ESTIMATES

a) Reserves by category and product under forecast prices and costs:

As at December 31, 2004

Reserve Estimates Category	Light and Medium Oil (mmbbls)	Heavy Oil (mmbbls)	Natural Gas (bcf)	Natural Gas Liquids (mmbbls)
Proved				
Developed producing	103	48	542	13
Developed non-producing	11	2	34	1
Undeveloped	21	2	61	2
Total proved	135	52	637	16
Probable	25	10	124	2
Total proved plus probable (1)	160	62	761	18

(1) Working interest reserves before royalties.

Penn West's 2004 reserves were 100 percent evaluated by Gilbert Laustsen Jung Associates Ltd. The reserve estimates have been calculated in compliance with the National Instrument 51-101 Standards of Disclosure ("NI 51-101"). Under NI 51-101, proved reserve estimates are defined as having a 90 percent probability that actual reserves recovered over time will equal or exceed proved reserve estimates. In calculating probable reserves under NI 51-101, there are equal (50 percent) probabilities that the actual reserves to be recovered will be less than or greater than the proved and probable reserves estimate.

In accordance with NI 51-101, proved undeveloped reserves have been recognized in cases where plans are in place to bring the reserves on production within a short, well-defined time frame. Proved undeveloped reserves often involve infill drilling in existing pools. It should be noted that no proved or probable reserves have been booked for coalbed methane or for CO_2 miscible flooding in the Pembina area.

Additional reserve disclosure tables, as required under NI 51-101, are contained in the Company's Annual Information Form filed on Sedar.

b) Reconciliation of Company working interest reserves by principal product type under forecast prices and costs:

	Oil and Liquids			Natural Gas			Barrels of Oil Equivalent		
Reconciliation Items [1]	Proved (mmbbls)	Probable (mmbbls)	Proved Plus Probable (mmbbls)	Proved (bcf)	Probable (bcf)	Proved Plus Probable (bcf)	Proved (mmboe)	Probable (mmboe)	Proved Plus Probable (mmboe)
December 31, 2003	190.0	32.4	222.4	697.8	115.5	813.3	306.3	51.6	357.9
Extensions	1.9	0.3	2.2	19.5	6.0	25.5	5.1	1.3	6.4
Improved Recovery	4.5	2.0	6.5	20.8	5.8	26.6	8.0	2.9	10.9
Technical and Economic Revisions	(3.9)	(2.9)	(6.8)	(43.4)	(16.1)	(59.5)	(11.1)	(5.6)	(16.7)
Discoveries	0.3	0.1	0.4	14.8	2.8	17.6	2.7	0.6	3.3
Acquisitions	29.2	5.6	34.8	45.8	11.1	56.9	36.8	7.4	44.2
Dispositions	(0.5)	–	(0.5)	(4.2)	(1.5)	(5.7)	(1.1)	(0.4)	(1.5)
Production	(19.2)	–	(19.2)	(114.1)	–	(114.1)	(38.2)	–	(38.2)
December 31, 2004	**202.3**	**37.4**	**239.7**	**637.0**	**123.7**	**760.7**	**308.5**	**57.9**	**366.4**

(1) Columns may not add due to rounding.

The above reserve estimates are Company working interest reserves before the deduction of Crown royalties. A net reserve reconciliation after royalties will be included in the Company's Annual Information Form. Proved plus probable reserves of 366.4 mmboe at the end of 2004 were two percent higher than proved plus probable reserves of 357.9 mmboe at the end of 2003.

c) Net present values of future net revenue before income taxes under forecast prices and costs ($ millions):

	(Discounted)		
Reserve Category	5%	10%	15%
Proved			
Developed producing	$ 3,111	$ 2,603	$ 2,267
Developed non-producing	214	130	93
Undeveloped	308	186	111
Total proved	$ 3,633	$ 2,919	$ 2,471
Probable	626	407	295
Total proved plus probable	$ 4,259	$ 3,326	$ 2,766

Net present values are net of wellbore abandonment liabilities and are based on the price assumptions contained in the following table. Estimated future net revenues do not represent fair market value.

d) Summary of pricing and inflation rate assumptions as of December 31, 2004 under forecast prices and costs:

Year	WTI Cushing, Oklahoma (US$/bbl)	Edmonton Par Price 40° API (Cdn$/bbl)	Hardisty Heavy 12° API (Cdn$/bbl)	Cromer Medium 29° API (Cdn$/bbl)	Natural Gas AECO Gas Price (Cdn$/GJ)	Edmonton Propane (Cdn$/bbl)	Inflation Rates (%)	Exchange Rate (CAD/USD)
Historical								
2001	25.97	39.40	16.94	31.56	6.21	31.85	2.6	0.646
2002	26.08	40.33	26.57	35.48	4.04	21.39	2.2	0.637
2003	31.07	43.66	26.26	37.55	6.66	32.14	2.0	0.721
2004	41.38	52.96	29.11	35.75	6.88	35.09	2.0	0.769
Forecast								
2005	42.00	50.25	27.50	43.75	6.60	32.25	2.0	0.820
2006	40.00	47.75	28.50	41.50	6.35	30.50	2.0	0.820
2007	38.00	45.50	28.75	39.50	6.15	29.00	2.0	0.820
2008	36.00	43.25	27.25	37.75	6.00	27.75	2.0	0.820
2009	34.00	40.75	25.50	35.50	6.00	26.00	2.0	0.820
2010	33.00	39.50	24.75	34.25	6.00	25.25	2.0	0.820
2011	33.00	39.50	24.75	34.25	6.00	25.25	2.0	0.820
2012	33.00	39.50	24.75	34.25	6.00	25.25	2.0	0.820
2013	33.50	40.00	24.75	34.75	6.10	25.50	2.0	0.820
2014	34.00	40.75	25.50	35.50	6.20	26.00	2.0	0.820
2015	34.50	41.25	25.75	36.00	6.30	26.50	2.0	0.820
Increase thereafter	2%	2%	2%	2%	2%	2%	2.0	0.820

e) Future development costs under forecast prices and costs ($ millions):

Year	Proved Future Development Costs
2005	$ 170
2006	107
2007	23
2008	15
2009 and subsequent years	82
Undiscounted total	$ 397
Discounted @ 10% per year	$ 313

Community Responsibility and Involvement

We consider it important to support the communities where we operate and where our employees and their families live. We strive to remain connected with issues and events occurring in those communities, and to respond both to public need and the priorities and concerns of our employees.

In 2004, we made contributions to 307 different groups and charitable organizations. Some of these programs included internal matching of employees' contributions. In other cases, we made a financial contribution to an organization at which one or more of our employees volunteered. Overall contributions were higher than in 2003, in keeping with our growth.

Among the larger programs supported in 2004 were: the Calgary Health Trust (fourth year of a five-year commitment); Medicine Hat College (first year of a five-year commitment); University of Alberta (first year of a five-year commitment); Calgary Humane Society (first year of a three-year commitment); Drayton Valley and Brazeau Multi-Purpose Fieldhouse (first year of a five-year commitment); Mount Royal College (third year of a five-year commitment); Regina YMCA (second year of a four-year commitment); Alberta Children's Hospital Foundation (fourth year of a five-year commitment); and ongoing contributions to the United Way and Salvation Army.

In early 2005, our employees gave generously to various charities to support the Tsunami relief efforts in Southeast Asia. These donations, when combined with the Company's and federal government's matching programs, provided over $110,000 to the relief effort.

Penn West and its management group pledged $500,000 to the new Alberta Children's Hospital. The new hospital represents an unprecedented opportunity for our community to join together in support of excellence in pediatric health care.

Environment, Health and Safety

We are committed to minimizing the environmental impacts from oil and natural gas operations, and to involving stakeholders throughout the exploration, development, production and abandonment processes. Our environmental programs encompass resource conservation, stakeholder communication, carbon dioxide ("CO_2") sequestration and site abandonment/ reclamation.

Our continuing policy is to meet or exceed all provincial and federal laws, regulations and standards pertaining to the environment. Our Environmental Policy and Environmental Management Plan ("EMP") covers air, water, soil and waste issues associated with industry operations. Environmental Operation Guidelines are used to train our employees in the EMP's implementation and practical effects. In 2004, for the fourth consecutive year, we maintained Platinum Member Status with the Canadian Association of Petroleum Producers' Environment, Health and Safety Stewardship program.

In 2004, we continued to implement our long term liability management programs, such as well abandonment, facility abandonment and reclamation. Under this program we evaluate inactive wellbores to determine whether they could be economically reactivated or whether they should be abandoned and reclaimed. This is an extensive program that in 2004 resulted in the reactivation of 246 wells for production, abandonment of 83 uneconomic wells and the receipt of 35 reclamation certificates from the provincial regulator, indicating that the sites in question had been satisfactorily abandoned and reclaimed. Our liability management programs also include auditing of field facilities such as oil batteries, compressor stations and gas processing plants.

As a Company that periodically acquires producing assets, we are conscious of the need to perform due diligence related to environmental performance and compliance on any prospective acquisition. This includes internal reporting concerning any remediation or capital improvements required.

For the fourth consecutive year, we maintained Gold Level Status in the Voluntary Challenge and Registry, a cooperative effort by industry, government and environmental organizations to identify and reduce emissions of "greenhouse" gases such as CO_2. We continued our program to plan and test the infrastructure required to inject and permanently "sequester" CO_2 in hydrocarbon reservoirs. Our CO_2 miscible flood at Joffre injected a net 43,214 tonnes of CO_2 during 2004 and continued to provide valuable insights into transferring this technology to the much larger Pembina Cardium light oil pool.

During 2004, planning continued on our pilot scale CO_2 injection program at Pembina, with injection commencing in March 2005. If successful, this could lead to a much larger enhanced oil recovery program with potential to sequester very significant volumes of CO_2. In 2004, we continued to participate in studies to develop a cost effective system to source large volumes of CO_2 currently emitted within Alberta and transport them by pipeline for injection into producing oil fields in central Alberta.

Safety

We are committed to building a proactive safety culture throughout the Company. The Company's health and safety management system provides a managed approach to attain our safety goals and initiatives. The ultimate objective is to ensure a safe and productive workplace for our staff, contractors and the public.

In 2004, our Health and Safety action plan focused on demonstrating our management commitment and visibility, developing the safety skills of our managers and employees, and implementing our Safety Culture and Safety Management system. In this period, over 500 employees completed our SMART system training and successfully completed the Safety Essentials for Supervisors and Managers ("SEFSAM") program. In the last quarter of 2004, an evaluation of our health and safety management system was conducted by an independent auditor. This evaluation resulted in the Company receiving a "Certificate of Recognition" from Alberta Human Resources and Employment.

In 2005 and beyond, we will continue to promote a safe work environment for our employees, contractors and the public.

Recent Developments

Subsequent to March 22nd, 2005, the date of the following Management's Discussion and Analysis ("MD&A"), Penn West received a satisfactory advance income tax ruling from the Canada Revenue Agency regarding the tax consequences of its plan to convert the assets and operations of Penn West through a Plan of Arrangement into an energy income trust. As a result, the Company is reviewing its forecasts for 2005, and it is possible that updated forecasts may differ from the forecast outlined in the MD&A.

Management's Discussion and Analysis

For the year ended December 31, 2004

Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements and accompanying notes, prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). All dollar amounts are in thousands of Canadian dollars unless otherwise indicated. The calculations of barrels of oil equivalent (boe) are based on a conversion ratio of six thousand cubic feet of natural gas to one barrel of crude oil, however this could be misleading if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Unless otherwise indicated, all production volumes quoted are the Company's working interest share before royalties. This MD&A is dated March 22, 2005.

References to cash flow; cash flow per share – basic; cash flow per share – diluted and netbacks included in the MD&A are considered non-GAAP measures and may not be comparable to similar measures provided by other issuers. Cash flow represents cash flow from operating activities before changes in non-cash working capital, cash option payments and expenditures on abandonments. Management utilizes cash flow as a key measure to assess financial performance and the ability of the Company to finance future capital expenditures.

Certain 2003 and 2002 comparative financial information has been restated for a change in accounting policy and accounting reclassifications. For details of the change in accounting policy, please refer to *Critical Accounting Estimates, Asset Retirement Obligations* later in this MD&A. Certain comparative financial information was reclassified to conform with 2004 financial statement presentation. Certain transportation costs, previously reported as an offset to revenues, are now a separate expense item, and future income tax assets related to the current portion of stock-based compensation are now presented as a current future income tax asset rather than a component of the long term future income tax liability.

This MD&A contains forward-looking statements (forecasts) under applicable securities laws. Forward-looking statements are necessarily based upon assumptions and judgments with respect to the future including, but not limited to, the outlook for commodity prices and capital markets, the performance of producing wells and reservoirs, and the regulatory and legal environment. Many of these factors can be difficult to predict. As a result, the forward-looking statements are subject to known or unknown risks and uncertainties that could cause the actual results to differ materially from those anticipated or implied in the forward-looking statements.

Business Environment

Increased demand for commodities from growing economies such as China, and political instability in parts of the world, resulted in strong energy prices in 2004. The price of West Texas Intermediate ("WTI"), a benchmark for light crude oil, averaged US$41.47 per barrel in 2004 up 34 percent compared to 2003.

Increased heavy oil differentials in 2004 were due to the fact that a significant portion of 2004 incremental supply, especially from the Organization of Petroleum Exporting Countries ("OPEC"), was heavy oil and there was a shortage of upgrading capacity. The average 2004 heavy/light crude oil differential was $15.32 per barrel, an increase of 41 percent from $10.84 per barrel in 2003.

AECO natural gas prices were stable in 2004 averaging $6.59 per mcf compared to $6.67 per mcf in 2003. Concerns about overall North American inventory levels and the tight balance between supply and demand factors were the main contributors to this price level.

The benefit of the strength in commodity prices was partially offset by the strength of the Canadian dollar relative to the U.S. dollar and wider heavy oil differentials. Oil marketing contracts are based on WTI prices, therefore, the strengthening Canadian dollar reduces netbacks realized in Canadian dollars. The average exchange rate increased by eight percent to $0.769 CAD/USD in 2004 compared to $0.715 CAD/USD in 2003. The Canadian dollar's strength was the result of numerous factors, including differences between Canadian and U.S. interest rates and relatively large U.S. current account deficits. Strong commodity prices also impacted operating costs due to increases in energy, steel and other costs.

Penn West has a proven management team, dedicated employees and an established business plan. In terms of production, cash flow, reserves and market capitalization, the Company has progressed from a very small producer in 1992 to the top ranks of independent oil and natural gas producers in western Canada. We have a disciplined approach to business that stresses cost control and product balance. Using this discipline, we have shown the ability not only to explore for and develop reserves of crude oil and natural gas, but also to acquire and optimize producing fields of crude oil and natural gas. We have a diverse asset base in the Western Canada Sedimentary Basin divided into five core areas ranging from southern Saskatchewan to regions bordering the Northwest Territories. Our vision is to create shareholder value by:

- *Maintaining a strong balance sheet;*
- *Developing a portfolio of profitable exploration, development and research projects; and*
- *Effectively managing our diversified production base of light, medium and heavy crude oil and natural gas.*

Using our established business plan, we achieved record annual production and cash flow in 2004, as illustrated in the table below.

5. SHAREHOLDER VALUE MEASURES

Years ended December 31

	2004	2003	2002
Daily production per thousand shares (boe)	**2.0**	1.9	1.9
Cash flow per share ($)	**16.10**	15.11	8.70
Ratio of year end bank debt to annual cash flow	**0.6**	0.5	1.3

One component of our business plan is to maintain a strong balance sheet and thus provide the Company with the flexibility to take advantage of opportunities to create shareholder value. On February 18, 2004, the Company closed the acquisition of certain properties with production of 10,000 boe per day of conventional heavy oil and natural gas. These properties were an excellent fit with our existing southwest Saskatchewan core area properties and we are optimistic they will provide strong returns for our shareholders.

The factors that contribute to our success include an extensive land base of undeveloped land (5.8 million net acres at December 31, 2004), highly trained and motivated in house professional and technical staff, and a strong balance sheet that provides the flexibility to pursue a strategy of either organic growth or growth through cost effective acquisitions. The application of financial discipline has also been a key factor in achieving strong returns on investment.

The Company's three year financial returns are summarized in the table below:

6. PERFORMANCE INDICATORS

Years ended December 31

	2004	2003	2002
Return on capital employed (%)	**8.4**	15.9	6.6
Return on equity (%)	**15.3**	30.1	13.5

Review of Strategic Alternatives

The key item on Penn West's agenda in 2004 was the review of strategic alternatives to maximize value for the Company's shareholders. On August 20, 2004, the Company announced that the Board of Directors had recommended Penn West's assets be converted into an income trust. The conversion was contingent on receiving a satisfactory advance tax ruling from the Canada Revenue Agency.

At this date, the ruling remains pending. Upon receipt of a satisfactory ruling, Penn West intends to submit a Plan of Arrangement to shareholders for approval to effect the conversion. While this process has been lengthier than first hoped, feedback from shareholders suggests that a trust conversion remains their preference.

7. OIL AND NATURAL GAS REVENUES

Years ended December 31

($000s)	2004	2003	2002
Light oil and natural gas liquids	**$ 537,681**	$ 497,287	$ 429,695
Conventional heavy oil	**210,617**	113,707	97,276
Total liquids	**748,298**	610,994	526,971
Natural gas	**772,964**	783,188	481,426
Total	**$ 1,521,262**	$ 1,394,182	$ 1,008,397

8. 2004 INCREASES (DECREASES) IN GROSS REVENUES

($000s)	
Gross revenues – 2003	$ 1,394,182
Decrease in light oil and liquids production	(6,168)
Increase in light oil and liquids price	46,574
Increase in conventional heavy oil production	76,814
Increase in conventional heavy oil price	20,083
Decrease in natural gas production	(33,458)
Increase in natural gas price	23,235
Gross revenues – 2004	**$ 1,521,262**

Oil Revenues and Marketing

The Company's overall quality of crude oil remained high, averaging 28.5 degrees API in 2004. Light and medium oil and NGLs made up 33 percent of the Company's total production, with an average quality of 37 degrees API. Heavy oil, at 15 degrees API, accounted for 17 percent of the Company's production. The Company's light and heavy oil netbacks remained strong throughout 2004 despite wider differentials between WTI and Canadian heavy oil postings. Most of the Company's production is sold at the field level to various refiners and marketing companies.

Revenues from light oil and liquids increased eight percent to $538 million for the year ended December 31, 2004 from $497 million in 2003. This increase was attributable to higher average prices in 2004. The Company's average light oil and liquids price increased nine percent to $42.04 per barrel for the year ended December 31, 2004 from $38.40 per barrel in 2003, and the average daily production of light oil and liquids decreased two percent to 34,943 barrels per day in 2004 from 35,479 barrels per day in 2003.

Light oil and liquids revenues in the fourth quarter ("Q4") of 2004 were $154 million, an increase of 27 percent over Q4 2003 revenues of $121 million. This increase was due to significantly higher average prices in the 2004 quarter. The Company's average light oil and liquids price for Q4 2004 was $48.57 per barrel, an increase of 31 percent over the Q4 2003 average price of $36.94 per barrel. Production of 34,524 barrels per day of light oil and liquids was down three percent compared to production of 35,633 in Q4 of 2003.

For the year ended December 31, 2004, the Company received an average price of $48.09 per barrel for its light oil and NGL production before hedging (2003 – $39.84). Hedges reduced the netback price by $6.05 per barrel in 2004 compared to $1.44 per barrel in 2003. On average, the Company hedged approximately 40 percent of its liquid production in 2004. At December 31, 2004, and at the date of this MD&A, no crude oil volumes were hedged.

Hedging reduced the light oil and liquids price by $4.10 per barrel in Q4 2004 compared to a reduction of $0.12 per barrel in the same period in 2003. The price before hedging in Q4 2004 was $52.67 per barrel (2003 – $37.06).

Revenues from conventional heavy oil for the year ended December 31, 2004 increased 85 percent to $211 million from $114 million in the same period of 2003. This increase was attributable to the 2004 acquisition of conventional heavy oil properties and higher average prices. The Company's average conventional heavy oil price increased 11 percent to $31.73 per barrel in 2004 from $28.70 in 2003, and the average production of conventional heavy oil increased 67 percent to 18,136 barrels per day in 2004 from 10,853 barrels per day in 2003.

In the fourth quarter of 2004, conventional heavy oil revenues increased 112 percent to $53 million compared to $25 million in Q4 2003. This increase was also due to higher average prices in the quarter and increased production as a result of the acquisition of heavy oil properties. Conventional heavy oil prices were $29.89 per barrel in Q4 2004, an increase of 25 percent over Q4 2003 prices of $23.96 per barrel. Production in Q4 was up 68 percent to 19,257 barrels per day in 2004 compared to 11,446 barrels per day in 2003.

Natural Gas Revenues and Marketing

The Company maintains a significant weighting to the Alberta natural gas market, as this market offers a premium netback relative to other indices. As at December 31, 2004, the Company marketed approximately 86 percent of its natural gas sales directly, with the remaining 14 percent marketed by aggregator pools.

For the year ended December 31, 2004, Penn West received an average natural gas sales price of $6.68 per mcf, an increase of three percent from $6.48 per mcf in 2003. Revenues from natural gas decreased one percent in the year ended December 31, 2004 to $773 million from $783 million in 2003. Although pricing was higher in 2004 than in 2003, natural gas production of 316 mmcf per day in 2004 was five percent less than production of 331 mmcf per day in 2003, resulting in an overall reduction of natural gas revenue. The decrease in natural gas production in 2004 was attributable to natural reservoir declines.

Natural gas revenues in the fourth quarter of 2004 increased 18 percent to $193 million from $164 million in the same period in 2003. This was the result of higher natural gas prices in Q4 2004 partially offset by lower production volumes. Q4 2004 natural gas prices of $6.83 per mcf were 20 percent higher than Q4 2003 prices of $5.68 per mcf, and natural gas production of 307 mmcf per day in Q4 2004 was two percent lower than the 314 mmcf per day in Q4 2003.

The Company makes use of short term financial instruments at various times in the commodity price cycle to manage downside risk. On average, the Company hedged approximately 20 percent of its natural gas production in 2004. For the year ended December 31, 2004, natural gas hedging did not impact the sales price received compared to a $0.06 per mcf hedging loss in 2003. At December 31, 2004, the Company had an AECO costless collar in place hedging 75,000 GJ per day, representing approximately one-quarter of natural gas production for the period January 2005, to March 2005, with a floor price of $7.30 per GJ and a ceiling price of $13.10 per GJ.

9. ROYALTY EXPENSES

Years ended December 31

	2004	2003	2002
Royalties, net of Alberta Royalty Credit ($000s)	**$ 296,054**	$ 265,132	$ 188,898
Average rate ($/boe)	**$ 7.65**	$ 7.15	$ 5.20
Percentage of gross revenues	**20%**	19%	19%

The average royalty rate incurred was 20 percent for the year ended December 31, 2004 compared to 19 percent for the same period in 2003. The royalty rate comprises an oil and liquids royalty rate of 18 percent compared to 16 percent in 2003 and a natural gas royalty rate of 21 percent in both 2004 and 2003. The increase in the oil and liquids royalty rate is mainly attributable to larger hedging losses in 2004. The year-to-year royalty rates also vary with commodity prices and the proportion of oil production relative to natural gas production.

For the fourth quarter of 2004, the average royalty rate incurred was 20 percent compared to 18 percent in Q4 2003. The oil and liquids royalty component increased to 18 percent in Q4 2004 compared to 14 percent in Q4 2003 as a result of increased hedging losses in Q4 2004 and higher prices. The natural gas royalty rate was 22 percent in Q4 2004 compared to 21 percent in Q4 2003.

10. OPERATING EXPENSES

Years ended December 31

	2004	2003	2002
Operating expenses ($000s)	**$ 300,278**	$ 245,572	$ 210,932
Average cost ($/boe)	**$ 7.75**	$ 6.63	$ 5.81
Percentage of gross revenues	**20%**	18%	21%

For the year ended December 31, 2004, operating costs averaged $7.75 per boe, a 17 percent increase from the average cost of $6.63 per boe achieved in 2003. Operating costs are generally higher for oil properties, and in 2004 liquids production increased to 50 percent of total production compared to 46 percent in 2003. A significant portion of the Company's liquid production is light oil that commands a premium price, therefore, with increased light oil prices the Company is well positioned to absorb operating cost increases and still maintain high operating netbacks. Operating costs were impacted by increases in the costs of steel and energy, and the elevation of general oilfield service costs due to increased industry demand.

Light oil and liquids operating costs increased 10 percent to $12.80 per barrel in the year ended December 31, 2004 from $11.68 per barrel in the same period of 2003. Operating costs for conventional heavy oil increased 14 percent to $8.49 per barrel during 2004 from $7.48 per barrel in 2003. Operating costs for natural gas in 2004 were $0.69 per mcf, an increase of 30 percent from $0.53 per mcf in 2003.

Q4 2004 operating costs were $7.94 per boe, eight percent higher than Q4 2003 operating costs of $7.35 per boe. This increase was the result of the higher liquids production as a percentage of total production, higher steel and energy costs and increased industry demand for oilfield services.

Light oil and liquids operating costs in Q4 2004 increased six percent to $13.14 per barrel from $12.35 per barrel in Q4 2003 and natural gas operating costs increased 11 percent to $0.71 per mcf in Q4 2004 from $0.64 per mcf in Q4 2003.

11. NETBACKS

Years ended December 31

	2004	2003	2002
Light oil and natural gas liquids			
Production (bbls/day)	**34,943**	35,479	33,822
Price ($/bbl)	**$ 48.09**	$ 39.84	$ 36.26
Hedging loss ($/bbl)	**(6.05)**	(1.44)	(1.45)
Royalties ($/bbl)	**(7.86)**	(6.39)	(6.17)
Operating expenses ($/bbl)	**(12.80)**	(11.68)	(10.29)
Netback ($/bbl)	**$ 21.38**	$ 20.33	$ 18.35
Conventional heavy oil			
Production (bbls/day)	**18,136**	10,853	10,211
Price ($/bbl)	**$ 31.73**	$ 28.70	$ 26.10
Royalties ($/bbl)	**(4.62)**	(3.84)	(3.31)
Operating expenses ($/bbl)	**(8.49)**	(7.48)	(7.30)
Netback ($/bbl)	**$ 18.62**	$ 17.38	$ 15.49
Natural gas			
Production (mmcf/day)	**316.3**	331.3	332.7
Price ($/mcf)	**$ 6.68**	$ 6.54	$ 4.06
Hedging loss ($/mcf)	**–**	(0.06)	(0.09)
Royalties ($/mcf)	**(1.43)**	(1.38)	(0.83)
Operating expenses ($/mcf)	**(0.69)**	(0.53)	(0.46)
Netback ($/mcf)	**$ 4.56**	$ 4.57	$ 2.68

For the year ended December 31, 2004, the Company received an average light oil and liquids netback of $21.38 per barrel, an average conventional heavy oil netback of $18.62 per barrel, and a natural gas netback of $4.56 per mcf. The light oil and liquids netback was up five percent from $20.33 per barrel for the year ended December 31, 2003 due to higher average commodity prices, partially offset by higher royalties, hedging losses and operating expenses experienced in the year. The heavy oil netback was up seven percent from $17.38 per barrel in 2003 mainly due to higher prices, partially offset by the wider light/heavy oil price differential and higher royalties and operating costs. The netback for natural gas was relatively unchanged as the impact of higher royalties and operating costs were offset by higher prices in 2004.

In Q4 2004, the Company achieved an overall netback of $25.18 per boe comprised of an average light oil and liquids netback of $25.96 per barrel, an average conventional heavy oil netback of $17.15 per barrel, and an average natural gas netback of $4.61 per mcf. All products contributed to the 23 percent overall increase from $20.50 per boe in 2003. The Q4 2004 light oil and liquids netback increased 35 percent from $19.17 per barrel in Q4 2003, the netback for conventional heavy oil increased 33 percent from $12.85 per barrel in Q4 2003, and the natural gas netback increased 20 percent from $3.85 per mcf in Q4 2003. The increased netbacks in the quarter were the direct result of higher commodity prices partially offset by increased royalties and operating expenses.

12. GENERAL AND ADMINISTRATIVE EXPENSES

Years ended December 31

	2004	2003	2002
Gross expenses ($000s)	**$ 41,272**	$ 33,967	$ 26,182
Operator recoveries ($000s)	**(25,183)**	(21,463)	(15,859)
Net expenses ($000s)	**$ 16,089**	$ 12,504	$ 10,323
Gross general and administrative expenses – average cost ($/boe)	**$ 1.07**	$ 0.92	$ 0.72
Percentage of gross revenues	**3%**	2%	3%
Net general and administrative expenses – average cost ($/boe)	**$ 0.42**	$ 0.34	$ 0.28
Percentage of gross revenues	**1%**	1%	1%

Gross general and administrative expenses increased due to growth in staff levels required to manage the Company's larger asset base. Expressed on a unit of production basis, gross general and administrative costs increased 16 percent to $1.07 per boe for the year ended December 31, 2004 from $0.92 per boe in 2003. Net general and administrative expenses on a per unit basis increased 24 percent to $0.42 per boe in 2004 from $0.34 per boe in 2003.

Q4 2004 net general and administrative expenses were up 34 percent on a per unit basis to $0.55 per boe from $0.41 per boe in Q4 2003.

13. STOCK-BASED COMPENSATION PROVISION

Years ended December 31

	2004	2003	2002
Stock-based compensation ($000s)	**$ 84,136**	$ 48,002	–
Average cost ($/boe)	**$ 2.17**	$ 1.30	–
Percentage of gross revenues	**6%**	3%	–

The Company's Stock Option Plan provides option holders the right to receive cash on the exercise of stock options. As a result, stock-based compensation costs of $84 million were recorded in 2004 (2003 – $48 million). Cash payments of $15.6 million (2003 – $13.6 million) were made during 2004 on the exercise of 523,305 stock options (2003 – 741,820 stock options). These payments were charged to the stock-based compensation liability.

Stock-based compensation of $22 million in Q4 2004 was up 214 percent from $7 million in Q4 2003. The increase was due to a $9.30 per share increase in the closing market price of Company common shares during Q4 2004 compared to an increase of $2.43 per share during Q4 2003.

14. FINANCING EXPENSES

Years ended December 31

	2004	2003	2002
Interest ($000s)	**$ 17,012**	$ 11,870	$ 20,310
Cash flow times interest coverage	**51.9**	69.5	23.8
Average cost ($/boe)	**$ 0.45**	$ 0.32	$ 0.57
Percentage of gross revenues	**1%**	1%	2%

Interest expense for the year ended December 31, 2004 amounted to $17.0 million, an increase of 43 percent from $11.9 million in 2003. This increase reflects higher relative debt levels due to the acquisition of properties producing approximately 10,000 boe per day in February 2004 for $234 million, and the payment of a special one time dividend of $1.50 per share and quarterly dividends of $0.125 per share for total cash payments to shareholders of $108 million in 2004 (2003 – nil).

Q4 2004 interest expense of $4.3 million is 48 percent higher than Q4 2003 interest expense of $2.9 million as a result of higher average debt levels in the current quarter.

15. DEPLETION, DEPRECIATION AND ACCRETION

Years ended December 31

	2004	2003	2002
Depletion and depreciation ($000s)	**$ 394,324**	$ 291,867	$ 237,954
Accretion ($000s)	**18,750**	11,795	10,082
	$ 413,074	$ 303,662	$ 248,036
Average rate ($/boe)	**$ 10.67**	$ 8.19	$ 6.83
Percentage of gross revenues	**27%**	22%	25%

The depletion, depreciation and accretion provision increased by 36 percent to $413 million in 2004 from $304 million in 2003, and by 29 percent in Q4 2004 to $116 million from $90 million in Q4 2003. These increases are the result of an increase in the fourth quarter 2004 depletion rate to $11.19 per boe (fourth quarter 2003 – $9.45 per boe). The average depletion and depreciation rate, excluding accretion, for the year increased by 29 percent to $10.18 per boe in 2004 from $7.87 per boe in 2003.

16. FOREIGN EXCHANGE

Years ended December 31

	2004	2003	2002
Foreign exchange (gain) loss ($000s)	**$ (27,708)**	$ (95,574)	$ 4,482
(Gain) loss from written Canadian dollar calls ($000s)	**(12,686)**	12,686	–
Net foreign exchange (gain) loss ($000s)	**$ (40,394)**	$ (82,888)	$ 4,482
Average (gain) loss ($/boe)	**$ (1.04)**	$ (2.24)	$ 0.12
Percentage of gross revenues	**3%**	6%	0.4%

As at December 31, 2004, the Company had $290 million of US denominated debt (2003 – US$340 million). The translation of the outstanding U.S. dollar bank loans to Canadian dollars, using exchange rates in effect at year end, resulted in an unrealized foreign exchange gain of $12 million for 2004, versus an unrealized foreign exchange gain of $96 million in 2003. The unrealized gain in 2003 was reduced by the unrealized loss of $13 million on Canadian dollar calls outstanding at December 31, 2003. These calls expired in 2004 with no cost to the Company, which eliminated the unrealized loss recorded in 2003.

In July 2004, the Company converted US$150 million of its U.S. denominated borrowings to Canadian dollars at an exchange rate of $0.755 CAD/USD resulting in a realized foreign exchange gain of $28.5 million. In January 2005, the Company converted US$80 million of U.S. denominated debt to Canadian dollars at an exchange rate of $0.831 CAD/USD and realized an additional foreign exchange gain of $24.9 million.

17. TAXES

Years ended December 31

	2004	2003	2002
Current income taxes ($000s)	**$ 17,834**	$ 9,898	$ 82,021
Future income taxes ($000s)	**109,568**	97,343	45,737
	$ 127,402	$ 107,241	$ 127,758
Effective tax rate	**31%**	19%	42%
Capital taxes ($000s)	**$ 10,146**	$ 10,150	$ 11,031

The provision for income taxes increased by 19 percent for the year ended December 31, 2004 to $127 million from $107 million in 2003. A non-recurring future income tax benefit of $20 million was recorded in 2004 reflecting a tax rate reduction enacted by the Government of Alberta in May 2004. This compares to a non-recurring future tax benefit of $100 million recorded in the year ended December 31, 2003 due to a reduction in both the federal and provincial tax rates. The 2003 provision was also impacted by larger foreign exchange gains. These gains are 50 percent taxable. The larger tax recovery and capital gains in 2003 are the main contributors to the lower 2003 tax provision even though income before taxes of $564 million in 2003 was 38 percent higher than 2004 income before taxes of $409 million.

The provision for income taxes in 2004 includes current taxes payable of $18 million, which was up 80 percent from $10 million in 2003 as a result of increased taxable income in the current year.

The Q4 2004 income tax provision of $35 million was 22 percent lower than the Q4 2003 income tax provision of $45 million.

18. TAX POOLS

At December 31

($ millions)		2004		2003		2002
Undepreciated capital cost (UCC)	$	276.4	$	270.1	$	440.6
Cumulative Canadian oil and gas property expense (COGPE)		611.5		679.2		852.7
Cumulative Canadian development expense (CDE)		95.4		136.6		128.5
Cumulative Canadian exploration expense (CEE)		–		–		1.4
Other		–		–		0.7
Total tax pools	$	983.3	$	1,085.9	$	1,423.9

19. ITEMS AFFECTING CASH FLOW AND NET INCOME

Years ended December 31

	2004		2003		2002	
	$/boe	%	$/boe	%	$/boe	%
Oil and natural gas revenues	$ 39.29	100	$ 37.62	100.0	$ 27.77	100
Net royalties	(7.65)	(19.5)	(7.15)	(19.0)	(5.20)	(18.7)
Operating expenses	(7.75)	(19.7)	(6.63)	(17.6)	(5.81)	(20.9)
Net operating income	23.89	60.8	23.84	63.4	16.76	60.4
Transportation	(0.66)	(1.7)	(0.71)	(1.9)	(0.59)	(2.1)
General and administrative expenses	(0.42)	(1.1)	(0.34)	(0.9)	(0.28)	(1.0)
Interest	(0.45)	(1.1)	(0.32)	(0.9)	(0.57)	(2.1)
Realized foreign exchange gain	0.74	1.9	–	–	–	–
Current and capital taxes	(0.71)	(1.8)	(0.54)	(1.4)	(2.56)	(9.2)
Cash flow from operations	22.39	57.0	21.93	58.3	12.76	46.0
Unrealized foreign exchange gain (loss)	0.30	0.8	2.24	6.0	(0.12)	(0.4)
Stock-based compensation	(2.17)	(5.5)	(1.30)	(3.5)	–	–
Depletion, depreciation and accretion	(10.67)	(27.2)	(8.19)	(21.8)	(6.83)	(24.6)
Future income taxes	(2.83)	(7.2)	(2.63)	(7.0)	(1.26)	(4.6)
Net income	$ 7.02	17.9	$ 12.05	32.0	$ 4.55	16.4

Cash flow increased by seven percent to $867 million for the year ended December 31, 2004 from $813 million in the same period of 2003. Basic cash flow per share rose by seven percent to $16.10 per share in 2004, compared to $15.11 per share in 2003.

Q4 2004 cash flow was $238 million, an increase of 23 percent from $194 million in Q4 2003. Basic cash flow per share increased 23 percent to $4.41 per share in Q4 2004 compared to $3.60 per share in Q4 2003.

Net income for the year ended December 31, 2004 decreased by 39 percent to $272 million from $447 million in 2003. Basic net income per share decreased by 39 percent in 2004 to $5.05 per share from $8.30 per share in 2003.

Net income in Q4 2004 increased 77 percent to $69 million from $39 million in Q4 2003. Basic net income per share increased 76 percent to $1.27 per share in Q4 2004 from $0.72 per share in Q4 2003.

Market Risk Management

The Company is exposed to normal market risks inherent in the oil and natural gas business, including credit risk, commodity price risk, interest rate risk and foreign currency risk. The Company, from time to time, attempts to minimize exposure to these risks using financial instruments. Financial instruments are not used by the Company for trading or speculative purposes.

Credit Risk

Credit risk is the risk of loss if purchasers or counterparties do not fulfill their contractual obligations. All of the Company's receivables are with customers in the oil and natural gas industry and are subject to normal industry credit risk. In order to limit the risk of non-performance of counterparties to derivative instruments, the Company transacts only with financial institutions with high credit ratings and by obtaining security in certain circumstances.

Commodity Price Risk

Commodity price risk is the Company's most significant exposure. Crude oil prices are influenced by worldwide factors such as OPEC actions, supply and demand fundamentals, and political events. Natural gas prices are generally influenced by oil prices and North American natural gas supply and demand factors. Pursuant to Company policy, the Company may from time to time attempt to manage these risks through the use of costless collars up to a maximum of 50 percent of sales volumes.

Interest Rate Risk

The Company maintains its debt in floating-rate bank facilities resulting in exposure to fluctuations in short term interest rates. From time to time, the Company may increase the certainty of interest rates using financial instruments to swap floating interest rates to fixed interest rates.

Foreign Currency Rate Risk

Prices received for sales of crude oil and certain bank loans are referenced to, or denominated in, U.S. dollars. Accordingly, realized oil prices, interest costs and debt levels are impacted by CAD/USD exchange rates. When considered appropriate, the Company may use financial instruments to fix future exchange rates.

Liquidity and Capital Resources

20. CAPITALIZATION

At December 31

	2004		2003		2002	
	$ millions	**%**	$ millions	%	$ millions	%
Common share equity, at market	**$ 4,269**	**86.0**	$ 2,586	81.0	$ 2,203	75.4
Bank loan	**503**	**10.2**	442	13.8	598	20.5
Working capital deficiency	**190**	**3.8**	165	5.2	120	4.1
	$ 4,962	**100.0**	$ 3,193	100.0	$ 2,921	100.0

Penn West's closing market price on the Toronto Stock Exchange was $79.25 per share in 2004, $48.17 per share in 2003 and $41.00 per share in 2002. Total capitalization was $5.0 billion at December 31, 2004 compared to $3.2 billion at year end 2003.

The Company ended the year 2004 with increased annual average production and only slightly increased debt levels compared to year end 2003. The Company maintained its strong balance sheet during 2004 even though it paid $108 million in special and quarterly dividends during the 2004 year. The strong balance sheet provides the Company flexibility to pursue a variety of opportunities for 2005.

At year end 2004, Penn West had an aggregate borrowing limit of $840 million on its loan facility with a syndicate of chartered banks. The Company had drawn $503 million at year end 2004. This loan facility is subject to an annual review by the lenders and requires no principal repayments provided that tangible net worth and cash flow coverage tests are met. Penn West believes it has ample coverage under these tests and anticipates that the loan facility will be renewed.

The Company announced a Normal Course Issuer Bid through the facilities of the Toronto Stock Exchange effective March 8, 2004. For a period not to exceed one year, a maximum of five percent of the issued and outstanding common shares of the Company, being 2,689,796 shares, could be purchased for cancellation. No share purchases were made under this bid.

Business Risks

The Company's exploration, development, production and acquisition activities are conducted in the Western Canada Sedimentary Basin and involve a number of business risks. These risks include the uncertainty of replacing annual production and finding new reserves on an economic basis, the instability of commodity prices, exchange rates and interest rates, and other factors discussed under *Notice Regarding Forward-Looking Statements*.

To the extent practical, the Company mitigates these risks by employing highly trained and competent management and staff who manage these risks by:

- *Balancing the production portfolio between oil and natural gas;*
- *Pursuing numerous investing opportunities, including:*
    - *Low risk development projects;*
    - *Moderate risk exploration plays;*
    - *Strategic acquisitions; and,*
- *Maintaining low finding, operating and general and administrative costs.*

The Company's management team believes that these principles, validated through Penn West's twelve year track record of growth and profitability, will continue to apply under the current or alternative business models.

The oil and natural gas industry is subject to extensive government influence through taxation policies and environmental legislation. While taxation policy has remained relatively stable recently, there is always the potential for change.

The industry is also subject to extensive regulations imposed by governments related to the protection of the environment. Environmental legislation in western Canada has undergone major revisions that have resulted in environmental standards and compliance becoming more stringent. The Company is committed to meeting its responsibilities to protect the environment wherever it operates, and has instituted a series of controls and procedures with respect to environmental protection that meet the standards of the Environmental Code of Practice published by the Canadian Association of Petroleum Producers.

Future Prospects and Outlook

Focusing on its five core areas, the Company continues to generate economic prospects through acquisitions, exploration, exploitation and development. The Company believes its extensive undeveloped land base and high quality, long life reserves provide opportunities to add both reserves and production at relatively low risk.

Penn West has provided positive earnings in each quarter for the last twelve years. Fiscal responsibility has always played a major role in the timing of actions taken by our management team. With commodity prices currently at relatively high levels and market expectations that they will remain high, the Company believes it has a variety of capital reinvestment options to achieve strong returns for shareholders.

Penn West will continue to plan conservatively while emphasizing low costs and maximum efficiencies in its operations. Penn West's asset base, control of infrastructure and efficient operations provide a solid foundation to generate superior future rates of return with low risk.

Our capital expenditure program in the first quarter of 2005 is based on a "business as usual" approach and is estimated in the $190 to $220 million range. These expenditures will cover a drilling program of 140 to 170 net wells, versus 180 net wells drilled in the first quarter of 2004. For the balance of the year, our plans will vary with the timing of any potential change in strategic direction. Average annual production is forecast at 103,000 boe to 109,000 boe per day. Our current plans and budget are based on assumed average 2005 commodity prices of US$39 per barrel of WTI crude oil and US$6.25 per MMBTU of NYMEX gas, and a currency exchange rate of $0.80 CAD/USD.

Under these assumptions, Penn West is expected to generate 2005 pre-tax cash flow of $800 million to $850 million.

The results of operations and the forecasts noted above are sensitive to changes in production, commodity prices, foreign exchange rates and interest rates. The table below summarizes those sensitivities.

21. SENSITIVITIES

($ millions, except per share amounts)	Impact on 2005 Cash Flow	Impact on 2005 Net Income
Change of:		
$1.00 per barrel in liquids price	$ 18.4	$ 11.6
Per common share	0.34	0.21
1,000 barrels per day in daily liquids production	11.7	4.6
Per common share	0.22	0.08
$0.10 per mcf in natural gas price	8.1	5.1
Per common share	0.15	0.09
10 mmcf per day in daily natural gas production	17.3	6.2
Per common share	0.32	0.11
$0.01 in CAD/USD exchange rate	15.0	9.5
Per common share	0.28	0.17
1% in prime interest rate	6.0	3.8
Per common share	$ 0.11	$ 0.07

(Sensitivities exclude hedging impacts.)

22. COMMITMENTS

The Company has committed to certain payments over the next five years, in addition to regular payments under the Company's credit facilities, as follows:

($ millions)	2005	2006	2007	2008	2009	Thereafter
Transportation	$ 21.8	$ 11.4	$ 8.8	$ 6.7	$ 3.3	$ 2.5
Transportation (US$)	3.4	3.4	1.7	1.6	1.6	9.3
Electricity	2.1	2.1	2.1	2.1	2.1	2.8
Office lease	4.0	4.2	4.2	4.2	4.2	3.5

23. EQUITY INSTRUMENTS

Common shares issued	
As at December 31, 2004*	53,868,745
Issued on exercise of stock options	61,200
As at March 22, 2005	53,929,945
Stock options outstanding	
As at December 31, 2004*	3,728,980
Granted	48,700
Exercised for common shares	(61,200)
Exercised for cash	(130,075)
Forfeited	(34,450)
As at March 22, 2005	3,551,955

* See Note 7 to the consolidated financial statements.

Critical Accounting Estimates

The Company's significant accounting policies are detailed in Note 1 to the consolidated financial statements. In the determination of financial results, the Company must make certain significant accounting estimates as follows:

Full Cost Accounting

The Company uses the full cost method of accounting for oil and natural gas properties. The Company has used this methodology consistently since the existing management team assumed responsibility for the Company in 1992. Generally, all costs of exploring and developing oil and natural gas reserves are capitalized and depleted against associated oil and natural gas production using the unit-of-production method based on the estimated proved reserves.

The Company adopted the new oil and natural gas full cost accounting guideline effective January 1, 2004. The guideline changed the determination of the ceiling amount for ascertaining the recoverability of accumulated costs in a cost center. The ceiling amount for a cost center is based on the undiscounted cash flows from proved reserves, using future prices, and the cost of unproven properties. If the costs are determined not to be fully recoverable, they are written down to fair value. Fair value is estimated as the present value of expected future cash flows from proved and probable reserves, using future prices, and the value of unproved properties. The Company's estimated risk-free rate is used to determine present values.

The Company used a weighted average price of $41.07 per barrel for oil and natural gas liquids and $6.40 per mcf for natural gas in the determination of the ceiling amount at December 31, 2004. There was no impact on reported results due to the application of this guideline.

Oil and Natural Gas Reserves

All of the Company's reserves were evaluated by the independent petroleum engineering consultant Gilbert Laustsen Jung Associates Ltd. In both 2004 and 2003, reserves were determined in compliance with National Instrument 51-101. The evaluation of oil and natural gas reserves are, by their nature, based on complex extrapolations and models as well as other significant engineering, capital, pricing and cost assumptions. Reserve estimates are a key component in the calculation of depletion. In addition, reserves are a key component of value in the ceiling test. To the extent that the ceiling amount is less than the carrying amount of property, plant and equipment, a write down against income must be made.

Asset Retirement Obligations

Effective January 1, 2004, the Company retroactively adopted the new Asset Retirement Obligations ("ARO") accounting recommendations. The fair value of statutory, contractual or legal obligations to retire long-lived assets are recorded as an ARO liability with a corresponding increase to the carrying amount of the related asset. The recorded ARO liability increases over time for changes in its fair value through accretion charges to earnings. Revisions to the estimated amount or timing of the obligations are reflected as increases or decreases to the ARO liability. Actual asset retirement expenditures are charged to the ARO liability to the extent of the then recorded liability. Amounts capitalized to the related assets are amortized to income consistent with the depletion or depreciation of the underlying asset. Note 5 to the consolidated financial statements details the impact of adopting these accounting recommendations on the comparative financial statements.

Stock-Based Compensation

The Company has recognized the potential liability that could arise if option holders elected the cash settlement alternative at the period end share price. Provision is made for all vested options at the period end plus the portion of future option vestings attributable to the period. The stock-based compensation expense of future periods will vary with share prices and changes in outstanding options.

Financial Instruments

Financial instruments contracted by the Company and determined to be hedges are accounted for as a component of the hedged item such as oil price, natural gas price, electricity or interest costs. The change in market value of a financial instrument accounted for as a hedge is not recognized in the financial statements until the underlying oil or natural gas production, power or interest is realized. Net income could change if these impacts were immediately recognized in the financial statements. Market value changes of financial instruments determined not to be hedges, not qualifying as a hedge, or no longer effective as hedges, are fully recognized in the financial statements. There are, for certain financial instruments, several acceptable methods for determining a mark-to-market value at a point in time. These differences can directly impact reported results.

Accounting Changes

Effective January 1, 2004, the Company began accounting for certain transportation costs as expenses in the consolidated statements of income and retained earnings. This change had no impact on net income as it was a reclassification between revenue and expenses. Previously, these costs were netted against revenue. Comparative periods have been restated to conform with the current year presentation. Future income taxes related to the current portion of the stock-based compensation liability were reclassified to a current future income tax asset from a component of the long term future income tax liability.

Notice Regarding Forward-Looking Statements

This document contains certain forward-looking statements that can generally be identified as such because of the context of the statements. Forward-looking statements may contain words such as forecasts, expects, anticipates, plans, intends, projects, estimates, or words of a similar nature. Results may differ materially from those expressed or implied by the forward-looking statements as a result of known and unknown risks, uncertainties and other factors.

Such factors include, among others:

- *Changes in general economic, market and business conditions which will impact demand for and market prices of the Company's products;*
- *The ability of the Company to implement its business strategy;*
- *Availability and cost of borrowing;*
- *The ability of the Company to complete its capital programs;*
- *The ability of the Company to transport its products to market;*
- *Potential delays or changes in plans with respect to exploration or development projects;*
- *The success of exploration and development activities;*
- *The accuracy of reserve estimates;*
- *Actions by governmental authorities, government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations);*
- *Competitive actions of other entities, including increased competition from other oil and gas companies or from companies that provide alternative sources of energy; and,*
- *The occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events directly affecting assets and/or daily operations.*

Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available on the date the statements were made, events or circumstances could cause actual results to differ materially from those estimated or projected and expressed in, or implied by, these forward-looking statements.

Future Accounting Pronouncements

Earnings Per Share

Effective January 1, 2005, this accounting pronouncement will require the number of incremental shares included in the year-to-date diluted earnings per share calculation be computed using the average market price of common shares for the year-to-date period. It also stipulates that contracts which could be settled in cash or common shares be settled in common shares, if share settlement is more dilutive. Shares to be issued upon conversion of a mandatorily convertible instrument would be included in the basic weighted average earnings per share calculation from the date when conversion becomes mandatory. These changes will not materially impact the Company's diluted earnings per share calculations.

Consolidation of Variable Interest Entities

Effective January 1, 2005, this accounting guideline addresses the circumstances where an entity has control of another entity through arrangements other than share ownership. The accounting guideline requires an enterprise to consolidate the entity when that enterprise has a variable interest that will absorb a majority of the entity's returns or losses. As the Company does not currently have any such arrangements, no impact is expected from the implementation of this guideline.

Financial Instruments, Other Comprehensive Income

This exposure draft addresses when to recognize and how to measure a financial instrument on the balance sheet and how gains and losses are to be presented. An additional financial statement, "other comprehensive income", will be required. Once implemented, the fair value of financial instruments, designated as hedges, will be included on the balance sheet with the related gain or loss recognized in other comprehensive income. Consistent with current practice, financial instruments not designated as hedges will be valued at market with the related gains and losses recognized in net income.

Management's Report

The consolidated financial statements of Penn West Petroleum Ltd. were prepared by management in accordance with accounting principles generally accepted in Canada. In preparing the financial statements, management has made estimates because a precise determination of certain assets and liabilities is dependent on future events. The financial and operating information presented in this report is consistent with that shown in the financial statements.

Management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of relevant, reliable and timely financial records for the preparation of statements.

The consolidated financial statements have been examined by the external auditors and approved by the Board of Directors. The Board of Directors' financial statement related responsibilities are fulfilled through the Audit Committee. The Audit Committee is composed entirely of independent directors. The Audit Committee recommends appointment of the external auditors to the Board of Directors, ensures their independence, and approves their fees. The Audit Committee meets regularly with management and the external auditors to discuss reporting and control issues and to ensure each party is properly discharging its responsibilities. The auditors have full and unrestricted access to the Audit Committee to discuss their audit and their related findings as to the integrity of the financial reporting process.

Gerry J. Elms
Vice President, Finance
and Corporate Secretary

Todd H. Takeyasu
Treasurer

William E. Andrew
President

February 28, 2005

Auditors' Report to Shareholders

We have audited the consolidated balance sheets of Penn West Petroleum Ltd. as at December 31, 2004 and 2003 and the consolidated statements of income and retained earnings and cash flow for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Calgary, Canada
February 28, 2005

KPMG LLP
Chartered Accountants

Consolidated Balance Sheets

December 31

($000s)	2004	2003*
ASSETS		
Current		
Accounts receivable	$ 160,479	$ 141,574
Taxes receivable	–	26,257
Future income taxes (Note 6)	25,310	8,121
Other	19,824	16,539
	205,613	192,491
Property, plant and equipment (Note 2)	3,661,844	3,117,166
	$ 3,867,457	$ 3,309,657
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	$ 306,596	$ 248,174
Taxes payable	11,174	–
Dividends payable	6,733	87,405
Stock-based compensation (Note 3)	71,017	22,111
	395,520	357,690
Bank loan (Note 4)	503,056	442,394
Asset retirement obligations (Note 5)	180,753	172,761
Stock-based compensation, net of taxes (Note 3)	20,951	5,806
Future income taxes (Note 6)	858,245	676,738
	1,563,005	1,297,699
Shareholders' equity		
Share capital (Note 7)	515,284	505,569
Retained earnings	1,393,648	1,148,699
	1,908,932	1,654,268
	$ 3,867,457	$ 3,309,657

See accompanying notes to the consolidated financial statements.
*Restated, see Note 11.

Approved on behalf of the Board:

N. Murray Edwards
Chairman

Denis L. Russell
Director

Consolidated Statements of Income and Retained Earnings

Years ended December 31

($000s, except per share amounts)		2004		2003*
Revenues				
Oil and natural gas	$	1,521,262	$	1,394,182
Royalties		(296,054)		(265,132)
		1,225,208		1,129,050
Expenses				
Operating		300,278		245,572
Transportation		25,600		26,359
General and administrative		16,089		12,504
Interest on long term debt		17,012		11,8
Depletion, depreciation and accretion		413,074		303,662
Stock-based compensation (Note 3)		84,136		48,002
Foreign exchange gain		(40,394)		(82,888)
		815,795		565,081
Income before taxes		409,413		563,969
Taxes				
Capital		10,146		10,150
Current income (Note 6)		17,834		9,898
Future income (Note 6)		109,568		97,343
		137,548		117,391
Net income	$	271,865	$	446,578
Retained earnings, beginning of year				
As previously reported	$	1,115,457	$	809,216
Accounting change (Note 5)		33,242		21,615
As restated		1,148,699		830,831
Net income		271,865		446,578
Dividends		(26,916)		(87,405)
Purchase of common shares (Note 7)		–		(41,305)
Retained earnings, end of year	$	1,393,648	$	1,148,699
Net income per common share (Note 8)				
Basic	$	5.05	$	8.30
Diluted	$	4.96	$	8.19

See accompanying notes to the consolidated financial statements.
*Restated, see Note 11.

Consolidated Statements of Cash Flow

Years ended December 31

($000s)		2004		2003*
Operating activities				
Net income	**$**	**271,865**	$	446,578
Items not involving cash				
Depletion, depreciation and accretion		**413,074**		303,662
Future income taxes		**109,568**		97,343
Unrealized foreign exchange gain		**(11,909)**		(82,888)
Stock-based compensation (Note 3)		**84,136**		48,002
Cash flow		**866,734**		812,697
Decrease (increase) in non-cash working capital (Note 10)		**23,505**		(114,632)
Payments for surrendered options (Note 3)		**(15,613)**		(13,572)
Expenditures on abandonments		**(29,558)**		(14,314)
Cash from operating activities		**845,068**		670,179
Investing activities				
Additions to property, plant and equipment		**(883,708)**		(730,581)
Proceeds on sales of property, plant and equipment		**18,256**		101,180
Decrease in non-cash working capital (Note 10)		**50,024**		58,207
Cash used in investing activities		**(815,428)**		(571,194)
Financing activities				
Increase (decrease) in bank loan		**72,571**		(73,153)
Issue of common shares		**5,243**		26,714
Dividends paid		**(107,588)**		–
Purchase of common shares		**–**		(52,768)
Decrease in non-cash working capital (Note 10)		**134**		222
Cash used in financing activities		**(29,640)**		(98,985)
Increase in cash		**–**		–
Cash and cash equivalents, beginning of year		**–**		–
Cash and cash equivalents, end of year	**$**	**–**	$	–
Interest paid	**$**	**16,986**	$	12,369
Income and capital taxes (recovered) paid	**$**	**(9,452)**	$	140,579

See accompanying notes to the consolidated financial statements.
*Restated, see Note 11.

Notes to the Consolidated Financial Statements

(all tabular amounts in $000s, except share and per share amounts)

1. Summary of significant accounting policies

These consolidated financial statements were prepared in accordance with generally accepted accounting principles in Canada. These principles require management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingencies at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods.

a) Principles of consolidation

The consolidated financial statements include the accounts of Penn West Petroleum Ltd. (the "Company") and all its wholly owned subsidiaries and partnerships.

b) Other current assets

Other current assets include deposits, prepayments and inventory. Inventories are valued at the lower of cost and net realizable value.

c) Property, plant and equipment

I) CAPITALIZED COSTS

The full cost method of accounting for oil and natural gas operations is followed whereby all costs of acquiring, exploring and developing oil and natural gas reserves are capitalized. These costs include lease acquisition, geological and geophysical, exploration and development and related equipment costs. Proceeds from the disposition of oil and natural gas properties are accounted for as a reduction of capitalized costs, with no gain or loss recognized unless such disposition results in a significant change in the depletion and depreciation rate.

II) DEPLETION AND DEPRECIATION

Depletion and depreciation of resource properties is calculated using the unit-of-production method based on production volumes before royalties in relation to total proved reserves as estimated by independent petroleum engineers. Natural gas volumes are converted to equivalent oil volumes based upon the relative energy content of six thousand cubic feet of natural gas to one barrel of oil. In determining its depletion base, the Company includes estimated future costs to be incurred in developing proved reserves and excludes estimated facility and equipment salvage values and the cost of unevaluated property. Significant natural gas processing facilities, net of estimated salvage values, are depreciated using the declining balance method over the estimated useful lives of the facilities.

III) CEILING TEST

The recoverability of accumulated costs in a cost center is assessed based on undiscounted future cash flows from proved reserves and the cost of unproven properties. If accumulated costs are assessed to be not fully recoverable, the cost center is written down to its fair value estimated as the present value of expected future cash flows from proved and probable reserves and the value of unproved properties. Expected future cash flows are discounted at the Company's estimated risk free rate.

IV) ASSET RETIREMENT OBLIGATIONS

The fair value of legal obligations for property abandonment and site restoration is recognized as a liability on the balance sheet as incurred with a corresponding increase to the carrying amount of the related asset. Changes in the fair value of the liability over time are reflected as accretion charges included in depletion, depreciation and accretion. Revisions to the estimated amount or timing of the obligations are reflected as increases or decreases to the recorded liability. Asset retirement expenditures, up to the recorded liability at the time, are charged to the liability. Amounts capitalized to the related assets are amortized to income consistent with the depletion or depreciation of the underlying asset.

The estimates in ii) and iii) and iv) are based on forecast sales prices, costs and regulations expected at the end of the fiscal year.

d) Joint ventures

Some of the Company's exploration and development activities are conducted jointly with others. The accounts reflect only the Company's proportionate interest in such activities.

e) Hedging activities

The Company may use financial instruments to hedge exposure to fluctuations in oil and natural gas prices, electricity costs, exchange rates and interest rates. All contracted financial instruments are assessed for effectiveness as hedges and may be designated as hedges if certain criteria are met.

Gains or losses on oil and natural gas related instruments designated as a hedge are reported as adjustments to oil and natural gas revenues when the related production is sold. Gains or losses on electricity rate transactions designated as a hedge are recorded as adjustments to operating expenses when the related power is consumed. Gains or losses on interest rate hedging transactions are reported as adjustments to interest on long term debt over the period hedged. Gains or losses on foreign exchange hedging transactions are recognized as foreign exchange gain or loss or as an adjustment to oil revenues.

Financial instruments not designated as a hedge, not qualifying as a hedge, or no longer effective as a hedge are recorded on the balance sheet as an asset or liability with changes to the market value reflected in net income.

f) Enhanced oil recovery

The value of proprietary injectants is not recognized as revenue until re-produced and sold to third parties. The cost of injectants purchased from third parties for miscible flood projects is included in property, plant and equipment. Deferred injectant costs are amortized as depletion and depreciation over the period of expected future economic benefit on a straight-line basis. Costs associated with the production of proprietary injectants are expensed.

g) Foreign currency translation

Monetary items, such as receivables and borrowings, are translated to Canadian dollars at the rate of exchange in effect at the balance sheet date. Non-monetary items, such as property, plant and equipment, are translated to Canadian dollars at the rates of exchange in effect when the transaction occurred. Revenues and expenses denominated in foreign currencies are translated at the average exchange rates in effect during the period. Foreign exchange gains or losses on translation are included in net income.

h) Stock-based compensation

The Company has a stock option plan and an employee stock savings plan, as described in Note 7.

As the stock option plan includes a cash settlement alternative, stock-based compensation cost is measured for stock options outstanding at intrinsic value and recognized as an expense over the vesting period. Intrinsic value is the difference between the exercise price of stock options and the trading price of common shares at the end of the measured period. Provision is made for all vested options at the period end plus the portion of future option vestings attributable to the current period. Changes in intrinsic value of outstanding options between the grant date and the measurement date are reflected as stock-based compensation cost. Cash payments made on option exercises are charged against the stock-based compensation liability to the extent that prior provision was made for the payment. Payments in excess of the recorded liability are charged to stock-based compensation cost.

Costs in respect to the employee stock savings plan are expensed as incurred.

i) Revenue recognition

Revenues from the sale of crude oil, natural gas liquids and natural gas are recognized when title passes from the Company to the purchaser. Sales below or in excess of the Company's working interest share of production are recorded as inventory or deferred revenue, respectively.

j) Income taxes

The Company uses the liability method of accounting for future income taxes. Timing differences are calculated assuming that the financial assets and liabilities will be settled at their carrying amount. Future income taxes are computed on temporary differences using income tax rates that are expected to apply when future income tax assets and liabilities are realized or settled.

2. Property, plant and equipment

December 31,	2004	2003*
Oil and natural gas properties, and production and processing equipment	**$ 5,241,817**	$ 4,303,533
Other	**12,702**	11,984
	5,254,519	4,315,517
Accumulated depletion and depreciation	**(1,592,675)**	(1,198,351)
Net book value	**$ 3,661,844**	$ 3,117,166

*Restated, see Note 11.

During the years ended December 31, 2004 and 2003, no overhead expenses were capitalized. The cost of unevaluated property excluded from the depletion base as at December 31, 2004 was $284 million (2003 – $263 million). Estimated future capital to develop proved reserves of $397 million (2003 – $399 million) was included in the depletion base as at December 31, 2004.

3. Stock-based compensation

The Company commenced recording stock-based compensation costs in the second quarter of 2003. The continuity of the liability for stock-based compensation, based on the year end share price of $79.25 (2003 – $48.17), was as follows:

	2004	2003
Liability, beginning of year	**$ 27,917**	$ –
Provision	**84,136**	48,002
Cash payments on exercise of stock options	**(15,613)**	(13,572)
Liability settlements on stock options exercised for shares	**(4,472)**	(6,513)
Liability, end of year	**$ 91,968**	$ 27,917
Current portion*	**$ 71,017**	$ 22,111
Long term portion	**20,951**	5,806
	$ 91,968	$ 27,917

* The current portion of the stock-based compensation liability represents the Company's potential liability if all vested stock options, plus those vesting in the next year, were exercised for cash at the year end share price.

4. Bank loan

December 31,	2004	2003
Bankers' acceptances	**$ 154,181**	$ –
LIBOR advances (2004 – US$290 million, 2003 – US$340 million)	**348,875**	442,394
	$ 503,056	$ 442,394

The Company has a credit facility arranged with a syndicate of chartered banks that is unsecured and bears interest at the prime rate or bankers' acceptance rates plus a stamping fee and facility utilization fee. The maximum borrowing under the facility is $840 million consisting of a $765 million credit facility and a $75 million operating loan facility. The facility is subject to an annual review by the lenders at which time a lender can request conversion to a term loan with repayment in full after one year. As at December 31, 2004, the Company had outstanding letters of credit for $5.9 million (2003 – $6.6 million) that reduced the amount otherwise available to be drawn on the facilities.

In July 2004, the Company converted US$150 million of its U.S. denominated borrowings to Canadian dollars at an exchange rate of $0.755 CAD/USD resulting in a realized foreign exchange gain of $28.5 million. In January 2005, the Company converted US$80 million of its U.S. denominated borrowings to Canadian dollars at an exchange rate of $0.831 CAD/USD realizing an additional foreign exchange gain of $24.9 million.

5. Asset retirement obligations

Effective January 1, 2004, the Company retroactively adopted the new accounting recommendations for asset retirement obligations. The total future asset retirement obligation was estimated by management and external consultants, assuming current technology and enacted legislation, based on the Company's net interest in all wells and facilities. The obligation includes the estimated costs and timing of well and facility abandonments and the reclamation of associated sites. The impact of the new accounting recommendations on the comparative financial statements was as follows:

Consolidated Balance Sheet

As at December 31, 2003	As Reported	Change	As Restated
Assets			
Net property, plant and equipment	$ 2,953,658	$ 163,508	$ 3,117,166
Liabilities and shareholders' equity			
Deferred credits/stock-based compensation	67,563	(61,757)	5,806
Asset retirement obligations	–	172,761	172,761
Future income taxes	649,355	19,262	668,617
Retained earnings	$ 1,115,457	$ 33,242	$ 1,148,699

Consolidated Statement of Income and Retained Earnings

Year ended December 31, 2003	As Reported	Change	As Restated
Depletion, depreciation and accretion	$ 322,031	$ (30,164)	$ 291,867
Accretion (1)	–	11,795	11,795
Future income taxes	90,601	6,742	97,343
Net income	$ 434,951	$ 11,627	$ 446,578

(1) Included in depletion, depreciation and accretion.

Changes to asset retirement obligations were as follows:

	2004	2003
Asset retirement obligations at January 1	**$ 172,761**	$ 148,033
Liabilities incurred during the period	**18,800**	27,247
Liabilities settled during the period	**(29,558)**	(14,314)
Accretion	**18,750**	11,795
Asset retirement obligations at December 31	**$ 180,753**	$ 172,761

The total undiscounted, uninflated amount required to settle the asset retirement obligations at December 31, 2004 was $737 million. Asset retirement obligations were discounted using a credit-adjusted rate of 7.5 percent over the expected useful life of the underlying assets, which currently extends up to 50 years into the future with an average life of 22 years.

6. Income taxes

As at December 31, future income tax assets (liabilities) arose from temporary differences as follows:

	2004	2003
Property, plant and equipment	**$ (914,038)**	$ (727,927)
Asset retirement obligations	**64,420**	63,455
Bank loan	**(16,094)**	(14,399)
Stock-based compensation	**32,777**	10,254
Capital losses	**10,664**	–
Valuation allowance on capital losses	**(10,664)**	–
	$ (832,935)	$ (668,617)
Current future income tax assets	**$ 25,310**	$ 8,121
Future income tax liability	**(858,245)**	(676,738)
	$ (832,935)	$ (668,617)

The provision for income taxes reflects an effective tax rate that differs from the combined federal and provincial statutory tax rate as follows:

Years ended December 31,	2004	2003
Income before taxes	**$ 409,413**	$ 563,969
Corporate income tax rate	**39.4%**	40.4%
Computed income tax provision	**$ 161,309**	$ 227,844
Increase (decrease) resulting from:		
Non-deductible Crown payments, net	**72,657**	87,445
Resource allowance	**(74,245)**	(89,166)
Tax rate reductions	**(20,237)**	(99,959)
Non-taxable foreign exchange	**(7,473)**	(14,399)
Other	**(4,609)**	(4,524)
Total income taxes	**$ 127,402**	$ 107,241
Current	**17,834**	9,898
Future	**109,568**	97,343
	$ 127,402	$ 107,241

7. Share capital

a) *Authorized*

i) Unlimited number of preferred shares issuable in one or more series.

ii) Unlimited number of voting common shares without nominal or par value.

b) *Issued*

Common shares	Number	Consideration
Balance, December 31, 2002	53,732,540	$ 483,805
Issued on exercise of stock options for common shares	1,208,750	26,714
Liability settlement on stock options exercised for shares		6,513
Purchase of shares under Normal Course Issuer Bid	(1,249,000)	(11,463)
Balance, December 31, 2003	53,692,290	$ 505,569
Issued on exercise of stock options for common shares	176,455	5,243
Liability settlement on stock options exercised for shares	–	4,472
Balance, December 31, 2004	**53,868,745**	**$ 515,284**

c) *Normal course issuer bid*

In February 2003, the Company announced its intention to make a Normal Course Issuer Bid (the "2003 Bid") through the facilities of the Toronto Stock Exchange. The 2003 Bid commenced on February 27, 2003 and continued until February 26, 2004. During this period, a maximum of five percent of the issued and outstanding common shares, being 2,687,824 shares, were eligible for purchase and cancellation. A total of 1,249,000 shares were purchased under the 2003 Bid, at an average cost of $42.25 per share and at a total cost of $53 million, of which $41 million was charged to retained earnings and $12 million was charged to share capital.

In March 2004, the Company announced another Normal Course Issuer Bid (the "2004 Bid"), through the facilities of the Toronto Stock Exchange. The 2004 Bid commenced on March 8, 2004 and extends for a maximum of one year. A maximum of five percent of the issued and outstanding common shares of the Company, being 2,689,796 shares, are eligible for purchase and cancellation. No shares were purchased under the 2004 Bid.

d) *Employee stock savings plan*

The Company has an employee stock savings plan (the "Savings Plan") for the benefit of all salaried employees. Under the Savings Plan, employees may elect to contribute up to 10 percent of their salary. In general, the Company matches employee contributions at a rate of $1.50 for each $1.00 of employee contribution. Employee contribution common shares may be issued from treasury at the average quarter-end market price or purchased in the open market. In 2004 and 2003, all employee contribution common shares were purchased in the open market. In 2004, 87,787 Company contribution common shares were purchased in the open market at an average price of $66.90 per common share and a total cost of $5.9 million (2003 – 97,533 shares at an average price of $43.39 per common share and a total cost of $4.2 million).

e) Stock options

The Company has a stock option plan ("the Plan") for the benefit of its employees and directors. Generally, stock options vest over a five year period and, if unexercised, expire six years from the date of grant. In the second quarter of 2003, the Plan was amended to provide option holders the right to receive cash for the surrender of vested stock options. To reflect the tandem nature of the plan in 2004, stock-based compensation costs of $84 million (2003 – $48 million) were charged to income.

During 2004, the Company paid $15.6 million for the surrender of 523,305 vested stock options (2003 – $13.6 million on 741,820 vested stock options) where the cash alternative was selected. These payments were charged against the stock-based compensation liability.

Total stock option activity relating to the Stock Option Plan was as follows:

	Shares		Weighted Average Exercise Price
Balance, December 31, 2002	5,005,750	$	29.97
Granted	1,563,850		41.32
Exercised for common shares	(1,208,750)		22.10
Exercised for cash	(741,820)		28.33
Forfeited	(392,240)	$	35.36
Balance, December 31, 2003	4,226,790	$	36.21
Granted	389,275		59.07
Exercised for common shares	(176,455)		29.71
Exercised for cash	(523,305)		31.92
Forfeited	(187,325)	$	46.35
Balance, December 31, 2004	**3,728,980**	**$**	**39.00**

As at December 31, 2004, there were 4,052,820 common shares (2003 – 4,229,275) reserved for future issuance. The table below summarizes information about stock options outstanding at December 31, 2004:

Range of Exercise Prices	**Outstanding as of December 31, 2004**	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	**Exercisable as of December 31, 2004**	Weighted Average Exercise Price
$15.00 – $22.50	**62,600**	0.2	$ 18.57	**62,600**	$ 18.57
$22.51 – $33.77	**879,790**	1.2	31.50	**621,070**	31.31
$33.78 – $50.63	**2,506,890**	3.7	39.70	**621,975**	38.88
$50.64 – $75.96	**279,700**	5.4	60.89	**–**	–
	3,728,980	3.2	$ 39.00	**1,305,645**	$ 34.30

As at December 31, 2004, options to purchase 1,305,645 shares (2003 – 875,480 shares) were exercisable.

8. Net income per share amounts

The Company follows the treasury stock method to compute the dilutive impact of stock options. The treasury stock method assumes that the proceeds received from the assumed exercise of in-the-money stock options are used to purchase common shares at average market prices.

The weighted average number of common shares used to calculate per share amounts was:

Years ended December 31,	2004	2003
Basic	**53,819,484**	53,793,072
Diluted	**54,802,957**	54,531,272

9. Financial instruments

Financial instruments, included in the balance sheets, are comprised of accounts and taxes receivable, current liabilities and the bank loan. The fair values of these financial instruments approximate their carrying amounts due to the short term maturity of the instruments and the market rate of interest and exchange rates applied to the bank loan.

All of the accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risk. The Company, from time to time, uses various types of financial instruments to reduce its exposure to fluctuating oil and natural gas prices, electricity costs, exchange rates and interest rates. The use of these instruments exposes the Company to credit risks associated with the possible non-performance of counterparties to derivative instruments. The Company limits this risk by transacting only with financial institutions with high credit ratings and by obtaining security in certain circumstances.

The Company's revenue from the sale of crude oil, natural gas liquids and natural gas is directly impacted by changes to the underlying commodity prices. To ensure that cash flows are sufficient to fund planned capital programs, costless collars may be utilized. These instruments ensure that commodity prices realized will fall into a contracted range for a contracted sales volume. Forward power contracts fix a portion of future electricity costs at levels determined to be economic by management.

Variations in interest rates directly impact interest costs. From time to time, the Company may increase the certainty of future interest rates using financial instruments to swap floating interest rates to fixed.

Crude oil sales and certain bank loans are referenced to or denominated in U.S. dollars. Accordingly, realized crude oil prices and debts in Canadian dollars are directly impacted by CAD/USD exchange rates. From time to time, the Company may use financial instruments to fix future exchange rates.

As at December 31, 2004, the Company had the following financial instruments outstanding:

	Notional Volume	Remaining Term	Pricing/Rate	Market Value* Year End
Natural gas				
AECO Costless Collars	75,000 GJ/d	Jan/05 to Mar/05	$7.30 to $13.10/GJ	$ 6,840
Electricity				
Alberta Power Pool Swaps	60 MW	2005	$41.00 to $50.00/MWh	2,092
Alberta Power Pool Swaps	60 MW	2006	$42.25 to $43.15/MWh	2,457
Alberta Power Pool Swaps	35 MW	2007	$46.00/MWh	$ 460

* Unrealized gain based on calculations using posted rates for similar contracts at the balance sheet date.

10. Cash flows

Changes in non-cash working capital items increased (decreased) cash and cash equivalents as follows:

Years ended December 31,	2004	2003
Accounts receivable	$ (18,905)	$ 4,013
Taxes receivable	26,257	(26,257)
Other current assets	(3,285)	(2,537)
Accounts payable and accrued liabilities	58,422	62,852
Taxes payable	11,174	(94,274)
	$ 73,663	$ (56,203)
Operating activities	$ 23,505	$ (114,632)
Investing activities	50,024	58,207
Financing activities	134	222
	$ 73,633	$ (56,203)

11. Accounting changes and 2003 financial statement reclassifications

Effective January 1, 2004, the Company retroactively adopted the accounting recommendations for Asset Retirement Obligations. The accounting policies are detailed in Note 1 c) iv) to these Consolidated Financial Statements. Comparative financial information has been restated as detailed in Note 5 to these Consolidated Financial Statements.

Certain transportation costs totalling $25,600 (2003 – $26,359) were retroactively reclassified from a component of oil and natural gas revenues to a separate expense in the Consolidated Statements of Income and Retained Earnings.

As detailed in Note 6 to these Consolidated Financial Statements, future income tax assets of $25,310 (2003 – $8,121) related to the current portion of the stock-based compensation liability were reclassified to a current future income tax asset from a component of the long term future income tax liability.

12. Strategic alternatives process

On August 20, 2004, the Board of Directors recommended that the assets of the Company be converted into an income trust contingent on receipt of a satisfactory advance tax ruling from the Canada Revenue Agency. To date, the ruling remains pending. Upon receipt of a satisfactory advance tax ruling, the Company intends to submit a Plan of Arrangement to shareholders for approval. If approved, the new business model could significantly impact future operations including dividend/distribution policies, capital programs, hedging activities, acquisition hurdle rates and compensation policies.

Summary Information – Five Year Summary

Years ended December 31

	2004	2003	2002	2001	2000
FINANCIAL					
($000s, except share and per share amounts)					
Gross revenues	**$ 1,521,262**	$ 1,394,182	$ 1,008,397	$ 1,096,567	$ 968,638
Cash flow	**866,734**	812,697	463,459	612,943	560,056
Basic per share	**16.10**	15.11	8.70	11.72	10.86
Diluted per share	**15.82**	14.90	8.48	11.36	10.46
Net income	**271,865**	446,578	165,204	248,108	225,656
Basic per share	**5.05**	8.30	3.10	4.74	4.37
Diluted per share	**4.96**	8.19	3.02	4.60	4.22
Capital expenditures	**865,452**	608,051	573,255	633,532	541,921
Total assets	**3,867,457**	3,309,657	2,933,324	2,507,821	2,085,479
Bank indebtedness	**503,056**	442,394	598,435	556,330	590,355
Shareholders' equity	**1,908,932**	1,654,268	1,314,636	1,128,920	866,459
Dividends declared					
Quarterly	**26,916**	6,723	–	–	–
Special	**–**	80,682	–	–	–
Total	**$ 26,916**	$ 87,405	$ –	$ –	$ –
Common shares outstanding at year end (000s):					
Basic	**53,869**	53,692	53,733	52,723	51,818
Basic plus options	**57,598**	57,919	58,738	58,109	56,945
Market value per common share					
High	**$ 81.99**	$ 49.50	$ 44.74	$ 45.25	$ 41.50
Low	**47.59**	35.77	32.76	30.30	28.25
Close	**$ 79.25**	$ 48.17	$ 41.00	$ 35.40	$ 37.40
OPERATING					
Production					
Light oil and natural gas liquids production (bbls/day)	**34,943**	35,479	33,822	29,375	24,262
Light oil and natural gas liquids price ($/bbl)	**$ 42.04**	$ 38.40	$ 34.81	$ 34.92	$ 37.54
Conventional heavy oil production (bbls/day)	**18,136**	10,853	10,211	9,509	8,200
Conventional heavy oil price ($/bbl)	**$ 31.73**	$ 28.70	$ 26.10	$ 20.24	$ 31.25
Total liquids production (bbls/day)	**53,079**	46,332	44,033	38,884	32,462
Total liquids price ($/bbl)	**$ 38.52**	$ 36.13	$ 32.79	$ 31.33	$ 35.95
Natural gas production (mmcf/day)	**316.3**	331.3	332.7	330.3	306.2
Natural gas price ($/mcf)	**$ 6.68**	$ 6.48	$ 3.97	$ 5.41	$ 4.84
Reserves (proved plus probable)					
Oil and liquids (mmbbls)	**239.7**	222.4	248.9	229.1	196.3
Natural gas (bcf)	**760.7**	813.3	1,012.7	1,071.4	1,078.8
Wells drilled (gross)					
Natural gas	**209**	307	209	274	228
Oil	**195**	337	112	118	129
Dry	**35**	106	44	61	48
Total wells drilled	**439**	750	365	453	405
UNDEVELOPED LAND HOLDINGS					
Western Canada (000 acres)					
Gross	**6,058**	5,538	4,402	3,672	3,030
Net	**5,767**	5,313	4,158	3,381	2,763
Average working interest (%)	**95**	96	94	92	91

Summary Information – Quarterly Summary

Three months ended,	2004 Mar 31	2004 June 30	2004 Sept 30	2004 Dec 31	2003 Mar 31	2003 June 30	2003 Sept 30	2003 Dec 31
FINANCIAL ($000s, except per share amounts, unaudited)								
Gross revenues	$ 346,075	$ 390,461	$ 384,300	$ 400,426	$ 398,767	$ 353,491	$ 331,459	$ 310,465
Cash flow	181,252	211,234	236,463	237,785	230,101	184,140	204,876	193,580
Basic per share	3.37	3.93	4.39	4.41	4.29	3.43	3.80	3.60
Diluted per share	3.32	3.86	4.31	4.33	4.20	3.38	3.77	3.55
Net income	60,975	65,520	76,775	68,595	137,863	192,483	77,361	38,871
Basic per share	1.13	1.22	1.43	1.27	2.57	3.58	1.43	0.72
Diluted per share	$ 1.12	$ 1.20	$ 1.40	$ 1.25	$ 2.52	$ 3.53	$ 1.42	$ 0.71
OPERATING								
Light oil and natural gas liquids production (bbls/day)	37,277	34,624	33,370	34,524	35,955	35,508	34,830	35,633
Light oil and natural gas liquids price ($/bbl)	$ 37.72	$ 39.80	$ 52.01	$ 48.57	$ 43.09	$ 36.61	$ 36.97	$ 36.94
Conventional heavy oil production (bbls/day)	13,968	19,692	19,596	19,257	10,466	10,256	11,230	11,446
Conventional heavy oil price ($/bbl)	$ 28.50	$ 30.17	$ 37.37	$ 29.89	$ 35.44	$ 28.72	$ 27.39	$ 23.96
Total liquids production (bbls/day)	51,245	54,316	52,966	53,781	46,421	45,764	46,060	47,079
Total liquids price ($/bbl)	$ 35.21	$ 36.30	$ 46.59	$ 41.88	$ 41.37	$ 34.83	$ 34.63	$ 33.78
Natural gas production (mmcf/day)	312.0	329.8	316.0	307.4	328.2	342.7	339.9	314.4
Natural gas price ($/mcf)	$ 6.41	$ 7.03	$ 6.43	$ 6.83	$ 7.65	$ 6.68	$ 5.91	$ 5.68

Conversions of Units

Imperial	Metric
1 ton	0.907 tonnes
1.102 tons	1 tonne
1 acre	0.40 hectares
2.5 acres	1 hectare
1 bbl	0.159 cubic metres
6.29 bbls	1 cubic metre
1 mcf	28.2 cubic metres
.035 mcf	1 cubic metre
1 mile	1.61 kilometres
0.62 miles	1 kilometre

Unless otherwise stated, all financial sums are stated in Canadian dollars.

Abbreviations

bbl	barrel (oil)
mmbbls	million barrels
bbls per day	barrels per day
boe	barrels of oil equivalent (based on 6 mcf of natural gas equals one barrel of oil)
mcf	thousand cubic feet (natural gas)
mmcf	million cubic feet
mmcf per day	million cubic feet per day
GJ	gigajoule
bcf	billion cubic feet
tcf	trillion cubic feet
API	American Petroleum Institute
TSX	Toronto Stock Exchange
WTI	West Texas Intermediate
MW	megawatt
MWh	megawatt-hour
mmbtu	million British thermal units

Our Employees

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Ray Abt
John Alexander
William Andrew
Brian Antoni
Edward Armagost
William Arthur
Kristine Arthur
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Kevin Bachman
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August Baier
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Hui Zhang
Laura Zhivov
Perry Zich
Travis Zubot
Sean Zunti

In Memory

In the past year, we were deeply saddened by the loss of Ross Hartley.
Our thoughts and prayers go out to his family and friends.

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President

David W. Middleton
Senior Vice President, Production

Donald J. Rae
Senior Vice President, Exploration

Bryan D. Clake
Vice President,
Corporate Development

Gerry J. Elms
Vice President, Finance and
Corporate Secretary

Thane A.E. Jensen
Vice President,
Engineering

Phil L. Reist
Vice President,
Controller

Directors

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Calgary, Alberta

John A. Brussa (3)(4)(5)
Calgary, Alberta

N. Murray Edwards (2)
Calgary, Alberta

Nabih A. Faris (1)(3)(4)(5)
West Vancouver, B.C.

Thomas E. Phillips (1)(3)(4)
Calgary, Alberta

Denis L. Russell (1)(5)
West Vancouver, B.C.

Notes:
(1) Member of the Audit Committee
(2) Member of the Executive Committee
(3) Member of the Compensation Committee
(4) Member of the Reserve Committee
(5) Member of the Corporate Governance Committee

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Calgary, Alberta

Thackray Burgess
Calgary, Alberta

Bennett Jones
Calgary, Alberta

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Canadian Imperial Bank
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Royal Bank of Canada
The Bank of Nova Scotia
Bank of Montreal
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Notes to Reader

1) This document contains forward-looking statements (forecasts) under applicable securities laws. Forward-looking statements are necessarily based upon assumptions and judgements with respect to the future including, but not limited to, the outlook for commodity markets and capital markets, the performance of producing wells and reservoirs, and the regulatory and legal environment. Many of these factors can be difficult to predict. As a result, the forward-looking statements are subject to known or unknown risks and uncertainties that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements.

2) All dollar amounts outlined in this document are expressed in Canadian dollars unless noted otherwise.

3) Where applicable, natural gas has been converted to barrels of oil equivalent (boe) using a conversion rate of 6 mcf of natural gas equals 1 boe. However, this could be misleading if used in isolation. A boe conversion of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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